IN THE MATTER OF an Arbitration under Chapter 3 of the IESO Market Rules made pursuant to section 32 of the Ontario *Electricity Act, 1998*, S.O. 1998, c. 15, as amended

B E T W E E N:

NEXUS ENERGY INC.

Applicant

- and -

INDEPENDENT ELECTRICITY SYSTEM OPERATOR (IESO)

Respondent

MEMORIAL OF THE APPLICANT, NEXUS ENERGY INC.

VOLUME ONE

October 31, 2025

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TAB 1

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Respondent

MEMORIAL OF THE APPLICANT

NEXUS ENERGY INC.

PART I - OVERVIEW

1. This case is about contractual breaches, unfair treatment and administrative overreach committed by the respondent Independent Electricity System Operator ("**IESO**") against the applicant Nexus Energy Inc. ("**Nexus Energy**").

2. The IESO is a public sector entity established under the Ontario *Electricity Act, 1998*[1]. Pursuant to the *Electricity Act*, the IESO is responsible for administering Ontario's wholesale electricity markets and ensuring that market participants, like Nexus Energy, comply with the governing IESO market rules.

[1] Ontario *Electricity Act, 1998*, S.O. 1998, c. 15, as amended ["***Electricity Act***"].

3. The IESO's compliance and enforcement authority is limited to that provided by the *Electricity Act* and, more pertinently, the IESO's market rules created under subsection 32(1) of the *Electricity Act* ("**Market Rules**").[2] As set out below, the Market Rules have the effect of a contract to which both the IESO and market participants like Nexus Energy are bound.

4. Put differently, the IESO does not have discretionary or other authority to undertake compliance and enforcement activities outside the four corners of the Market Rules. Doing so amounts to an unlawful exercise and overreach of administrative powers.

5. As a public authority created by statute, the IESO is also subject to common law administrative law principles including the requirement to make decisions in accordance with the duty of fairness owed to market participants like Nexus Energy.[3]

6. The subject of this Arbitration is the IESO's decision to issue a compliance notice and enforcement order against Nexus Energy pursuant to Chapter 3 of the IESO Market Rules for payment of $2,078,824.92 for "avoided congestion rents" (the "**Notice of Non-Compliance**" and "**IESO Order**" as described more particularly below). Nexus Energy challenges[4] the Notice of Non-Compliance and IESO Order on the bases that:

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[2] *Electricity Act,* ss 32(1).
[3] Huscroft, Grant, "From Natural Justice to Fairness: Thresholds, Content, and the Role of Judicial Review" in C.M Flood and L Sossin, eds., A*dministrative Law in Context*, 2nd ed (Toronto: Emond Montgomery, 2012) ["***Huscroft***"], p 153, p A85.
[4] Memorial of the Applicant, Tab 1, Affidavit of Robin Doolittle dated October 29, 2025 ["***Doolittle Affidavit***"], Exhibit "L", "Chapter 3 of the IESO Market Rules issued May 1, 2023", p 3, ss 2.2.1.1, p A376.

(a) the IESO does not have the authority (contractual or otherwise) under the Market Rules to seek payment from Nexus Energy for "avoided congestion rents";

(b) the IESO breached its duty of fairness owed to Nexus Energy; and

(c) Nexus Energy reasonably relied on the IESO's representations such that the IESO should be estopped from enforcing the Notice of Non-Compliance and IESO Order.

7. Each ground above is an independent and sufficient basis upon which to grant an arbitral award under Chapter 3, section 2.7.25 of the Market Rules to the following effect:

(a) Finding that in its compliance investigation against Nexus Energy (bearing compliance case number COM237240), the IESO (including MACD as defined below) misinterpreted and misapplied Chapter 3, section 6.6.10A[5];

(b) Directing the IESO (including MACD) to interpret and apply Chapter 3, section 6.6.10A such that "avoided congestion rents" are not recoverable from Nexus Energy;

(c) In the alternative to (a) and (b) above, prohibiting the IESO (including MACD) from enforcing the Notice of Non-Compliance and IESO Order

[5] *Doolittle Affidavit*, Exhibit "L", "Chapter 3 of the IESO Market Rules issued May 1, 2023", p 77, s 6.6.10A, p A450.

against Nexus Energy on the basis that such prohibition would be just and reasonable[6];

(d) Prohibiting the IESO (including MACD) from considering the Subject Transactions for the purpose of alleging and/or determining any future Market Rules breaches and from assessing future sanctions against Nexus Energy; and

(e) Directing the IESO to repay to Nexus Energy the sum of $2,078,824.92 within 30 days[7], plus prejudgment interest to be calculated in accordance with the *Courts of Justice Act* (Ontario) with necessary modifications.

8. Further and in any event of the outcome, given the circumstances of this case and the IESO's conduct, Nexus Energy respectfully requests an award of its costs including the costs of this Arbitration pursuant to Chapter 3, section 2.7.32.[8]

PART II - FACTS

The Parties

9. The IESO is responsible for the day-to-day operations of the provincial electricity system and for administering the competitive wholesale electricity markets in Ontario. Among other things, the IESO forecasts short-term and long-term electricity demand and

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[6] *Doolittle Affidavit*, Exhibit "L", "Chapter 3 of the IESO Market Rules issued May 1, 2023", pp 21-22, ss 2.7.25, pp A394-395.

[7] *Doolittle Affidavit*, Exhibit "L", "Chapter 3 of the IESO Market Rules issued May 1, 2023", p 26, ss 2.7.35, p A399.

[8] *Doolittle Affidavit*, Exhibit "L", "Chapter 3 of the IESO Market Rules issued May 1, 2023", p 25, ss 2.7.32, p A398; also see p 1, s 2.1.1 and 2.1.2, p A374.

procures the necessary electricity generation to balance supply and demand on a 24/7, 365-day basis every year.[9]

10. Nexus Energy is a privately-held corporation formed in 2017 with approximately 32 employees[10]. Nexus Energy became a registered energy trader market participant with the IESO in December 2017.[11]

11. As an IESO-registered energy trader, Nexus Energy is authorized to import and export energy over the interties ("inter-ties" or transmission lines) between Ontario and neighbouring electricity market jurisdictions such as New York Independent System Operator ("**NYISO**"), the Midcontinent Independent System Operator ("**MISO**"), the Pennsylvania Jersey Maryland Interconnection ("**PJM**"), and the ISO New England ("**ISO-NE**").[12]

12. More specifically, Nexus Energy trades electricity flows between certain North American jurisdictions (such as the IESO market in Ontario and the NYISO market in New York). These intertie transactions consist of <u>imports</u> of electricity into Ontario from another jurisdiction, or <u>exports</u> of electricity from Ontario to a neighbouring jurisdiction.[13]

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[9] *Doolittle Affidavit*, Exhibit "F", "IESO Notice of Non-Compliance dated December 17, 2024", Schedule A, p 3, para 5, p A232.

[10] *Doolittle Affidavit*, p 2, paras 3 and 5, p A129.

[11] *Doolittle Affidavit*, p 2, para 4, Exhibit "B", "Participation Agreement between Nexus Energy and IESO signed August 16, 2017", pp 1-15, pp A148-162.

[12] *Doolittle Affidavit*, p 2, para 7, p A129.

[13] *Doolittle Affidavit*, p 3, para 10, p A130.

13. Between December 2017 and December 2023, Nexus Energy scheduled over 40,000 import and export transactions through the IESO.[14] Of those transactions, approximately 1,658 or less than 4% are the subject of this Arbitration (the "**Subject Transactions**").[15]

IESO issues Notice of Alleged Breach against Nexus Energy

14. The IESO and Nexus Energy are required to comply with applicable Market Rules and associated IESO Market Manuals, which have the effect of a contract between the parties.[16]

15. Within the IESO, the IESO's Market Assessment and Compliance Division ("**MACD**") is responsible for enforcing the Market Rules.[17] This includes conducting compliance investigations to determine whether Market Rules have been breached and taking enforcement action against market participants for breaches of the Market Rules.[18]

16. On April 4, 2024, MACD sent a letter to Nexus Energy alleging that Nexus Energy breached certain of the Market Rules ("**Notice of Alleged Breach**").[19]

17. More specifically, the Notice of Alleged Breach states that MACD has commenced an investigation into whether each of the Subject Transactions constitutes a breach of

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[14] *Doolittle Affidavit*, Exhibit "F", "IESO Notice of Non-Compliance dated December 17, 2024", Schedule A, p 6, para 20, p A235.

[15] *Doolittle Affidavit*, p 2, para 6, p A129.

[16] *Doolittle Affidavit*, Exhibit "B", "Participation Agreement between Nexus Energy and IESO signed August 16, 2017", pp 2-4, Recital F and Article 3, p A149-151.

[17] *Doolittle Affidavit*, Exhibit "F", "IESO Notice of Non-Compliance dated December 17, 2024", Schedule A, p 3, para 3, p A232.

[18] *Doolittle Affidavit*, Exhibit "P", "IESO Market Manual 2.6: Treatment of Compliance Issues dated September 11, 2023", pp 13-14, s 1.4, pp A857-858.

[19] *Doolittle Affidavit*, Exhibit "C", "IESO Notice of Alleged Breach dated April 4, 2024", pp A164-209.

Chapter 7, section 7.5.8A of the Market Rules by failing to schedule the Subject Transactions "other than for bona fide and legitimate reasons".[20]

18. The Notice of Alleged Breach is signed by the Vice-President of MACD, Glenn McDonald.[21] The Notice of Alleged Breach says to contact Robert (Bob) Yeoman with any questions or concerns regarding the Notice of Alleged Breach.[22] Bob Yeoman reports directly to Glenn McDonald.[23]

19. That both Glenn McDonald and Robert Yeoman were involved in the preparation and issuance of the Notice of Alleged Breach and subsequent steps is relevant because there are important fairness concerns (including independence and bias) in how the IESO conducted the investigation and made decisions against Nexus Energy – all of which are discussed further below at paragraphs 87 to 102.

20. The Notice of Alleged Breach states that MACD assessed that Nexus Energy had "avoided congestion payments" in the total amount of $2,078,809.[24]

21. Despite the assurances provided under IESO Market Manual Part 2.6 (Treatment of Compliance Issues), MACD failed to first issue a "Market Rule Reminder" before issuing the Notice of Alleged Breach.[25]

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[20] *Doolittle Affidavit*, Exhibit "C", "IESO Notice of Alleged Breach dated April 4, 2024", p 2, para 4-5, p A165.

[21] *Doolittle Affidavit*, Exhibit "C", "IESO Notice of Alleged Breach dated April 4, 2024", p 5, p A168.

[22] *Doolittle Affidavit*, Exhibit "C", "IESO Notice of Alleged Breach dated April 4, 2024", p 4, para 17, p A167.

[23] Memorial of the Applicant, Tab 2, Affidavit of Francois Tardif dated October 29, 2025 ["***Tardif Affidavit***"], Exhibit "G", pp A1695-1703.

[24] *Doolittle Affidavit*, Exhibit "C", "IESO Notice of Alleged Breach dated April 4, 2024", pp 2-3, para 8, p A165-166.

[25] *Doolittle Affidavit*, Exhibit "P", "IESO Market Manual 2.6: Treatment of Compliance Issues dated September 11, 2023", p 4, ss 1.3.2, p A848.

22. Likewise, and despite the express requirement under IESO Market Manual Part 2.6, MACD failed to first issue a "Request for Information" before issuing the Notice of Alleged Breach.[26] Part 2.6 expressly provides that MACD "will send the market participant … an informal "Request for Information" prior to issuing a "Notice of Alleged Breach"", unless the case involves potential breaches of reliability standards or severe breaches (neither of which is alleged here).[27]

23. Instead, and without any prior warning, MACD issued the Notice of Alleged Breach in April 2024 - more than six years after the first of the Subject Transactions took place in December 2017.[28]

MACD fails to properly respond to Nexus Energy's information requests

24. The Notice of Alleged Breach was a surprise to Nexus Energy and caused it significant concern.[29] Nexus Energy immediately requested to meet with MACD to discuss the Notice of Alleged Breach, which meeting took place on April 12, 2024.[30] At the meeting, Nexus Energy asked MACD if and what opportunity Nexus Energy would have to review the purported "sources of evidence" listed in paragraph 13 of the Notice of Alleged Breach.[31] Much of this evidence has never been provided to Nexus Energy.

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[26] *Doolittle Affidavit*, Exhibit "P", "IESO Market Manual 2.6: Treatment of Compliance Issues dated September 11, 2023", p 4, ss 1.3.2, p A848.

[27] *Doolittle Affidavit*, Exhibit "P", "IESO Market Manual 2.6: Treatment of Compliance Issues dated September 11, 2023", p 4, ss 1.3.2, p A848.

[28] *Tardif Affidavit*, p 3, para 6, p A1652.

[29] *Doolittle Affidavit*, p 6, para 23, p A133; *Tardif Affidavit*, pp 3-4, 6, paras 7, 18, pp A1652-1653, A1661.

[30] *Tardif Affidavit*, p 7, para 20, p A1656.

[31] *Tardif Affidavit*, p 7, para 21, p A1656.

25. Nexus Energy also requested the following additional information from MACD to conduct its own analysis and prepare a written response to the Notice of Alleged Breach:

> *(a) the total export and import failure charges paid by Nexus Energy;*
>
> *(b) when Ontario was contemporaneously experiencing surplus baseload generation (**SBG**) conditions;*
>
> *(c) when Nexus Energy was the sole marginal bidder that set the intertie congestion price (**ICP**)*[32]*; and*
>
> *(d) the total number of failed MWs [mega-watts] at the relevant interties during the hours covered by the list attached as the Appendix to the Notice of Alleged Breach.*[33] (bolding added)

26. Instead of providing the requested information, or any other data or documents upon which the Notice of Alleged Breach purportedly relies, Bob Yeoman told Nexus Energy that his team was not required to respond to the information requests.[34] Nevertheless, Bob Yeoman said he would consider responding to some of the requests, but not all of them because doing so would be too burdensome.[35]

27. Accordingly, Nexus Energy reluctantly reduced its information requests to half of the items listed in paragraph 25 above.[36] Nexus Energy received responses to these reduced information requests almost seven weeks later.[37]

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[32] ICP (or "Intertie Congestion Price") appears to be treated by the IESO synonymously with "congestion rents" for the purpose of this dispute.

[33] *Tardif Affidavit*, p 7, para 22, Exhibit "B", "Email exchange between MACD and Nexus Energy dated May 6-9, 2024", p A1670.

[34] *Tardif Affidavit*, p 8, para 23, p A1657.

[35] *Tardif Affidavit*, p 8, para 23, p A1657.

[36] *Tardif Affidavit*, p 8, para 24, p A1657.

[37] *Tardif Affidavit*, p 8, para 25, Exhibit "B", "Email exchange between MACD and Nexus Energy dated May 6-9, 2024", p A1670.

28. Following its review and internal analysis, Nexus Energy prepared and sent to MACD on July 9, 2024 a written response to the Notice of Alleged Breach ("**Nexus Energy Response**").[38]

29. On September 4, 2024, Nexus Energy met again with MACD to discuss the Nexus Energy Response to the Notice of Alleged Breach.[39] Bob Yeoman was among the MACD representatives at the meeting.[40]

IESO issues Notice of Non-Compliance which fails to comply with Market Rules

30. On December 17, 2024, MACD issued a Notice of Non-Compliance stating that Nexus Energy was required to pay to the IESO $2,078,824.92 "in congestion rents avoided by NEXUS due to breaches regarding 1,658 transaction failures identified in the [Notice of Alleged Breach]".[41]

31. Enclosed with the Notice of Non-Compliance was the IESO Order requiring payment of **"$2,078,824.92 in congestion rents (ICPs) avoided by NEXUS"**.[42] This is the Notice of Non-Compliance and IESO Order at issue in this Arbitration.

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[38] *Tardif Affidavit*, p 10, para 30, p A1659; *Doolittle Affidavit*, Exhibit "F", "IESO Notice of Non-Compliance dated December 17, 2024, p 1, para 2, p A227.

[39] *Tardif Affidavit*, p 10, para 32, p A1659.

[40] *Tardif Affidavit*, p 10, para 32, p A1659.

[41] *Doolittle Affidavit*, Exhibit "F", "IESO Notice of Non-Compliance dated December 17, 2024", p 2, paras 5-6, p A228.

[42] *Doolittle Affidavit*, Exhibit "F", "IESO Notice of Non-Compliance dated December 17, 2024", Schedule A, p 21, para 92, p A250.

32. Contrary to Chapter 3, subsection 6.6.2.1 of the IESO Market Rules, the Notice of Non-Compliance does not indicate "the level of non-compliance" for the alleged breaches.[43]

33. Likewise, and contrary to Chapter 3, subsection 6.6.2.2 of the IESO Market Rules, the Notice of Non-Compliance does not indicate "the rate of recurrence of non-compliance" for the alleged breaches.[44]

34. As is the Notice of Alleged Breach, the Notice of Non-Compliance letter is signed by Glenn McDonald, with a cc: to Bob Yeoman, Director of Rule Compliance and Market Surveillance.[45]

IESO fails to participate in good faith in mandatory dispute resolution process

35. In December 2024, Nexus Energy commenced the IESO dispute resolution process challenging the Notice of Non-Compliance and IESO Order by filing a Notice of Dispute under the Market Rules.[46]

36. On January 15, 2025, pursuant to the first "good faith negotiations" step in the mandatory Market Rules dispute resolution process, Nexus Energy met with the IESO.[47] No one attended the meeting on behalf of the IESO other than the same MACD

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[43] *Doolittle Affidavit*, Exhibit "L", "Chapter 3 of the IESO Market Rules issued May 1, 2023", p 71, ss 6.6.2.1, p A444.
[44] *Doolittle Affidavit*, Exhibit "L", "Chapter 3 of the IESO Market Rules issued May 1, 2023", p 71, ss 6.6.2.1, p A444.
[45] *Doolittle Affidavit*, Exhibit "F", "IESO Notice of Non-Compliance dated December 17, 2024", p 3, p A229.
[46] *Tardif Affidavit*, Exhibit "D", "Nexus Energy's Notice of Dispute dated December 23, 2024", pp 25-32, p A1676-1682.
[47] *Doolittle Affidavit*, p 13, paras 49-50, p A140.

representatives that participated in the April 12, 2024 and September 4, 2024 meetings (and internal MACD lawyers).[48]

37. As Nexus Energy was engaging with mostly the same MACD staff with whom it had already had the April 12, 2024 and the September 4, 2024 meetings, including Bob Yeoman, it became quickly apparent to Nexus Energy that the "good faith negotiations" meeting would not result in a resolution to the dispute.[49]

38. Nexus Energy accordingly proceeded to the next stage of the IESO dispute resolution process, namely, mediation.[50]

39. Despite the requirement under Chapter 3, subsection 2.6.2 of its Market Rules, the IESO failed to ensure that its dispute resolution panel Secretary, the Honourable Frank Newbould Q.C., assigned one member of its dispute resolution panel to inquire into and act as mediator in respect of this dispute within five business days of the IESO's Response to the Notice of Dispute delivered on February 26, 2025.[51]

40. Subsequently, following a conference call with the parties on April 9, 2025, Secretary Newbould agreed to act as the mediator for the dispute.[52]

41. The mediation was held by Secretary Newbould in Toronto on May 16, 2025.[53] In attendance on behalf of the IESO were Bob Yeoman and other MACD representatives,

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[48] *Doolittle Affidavit*, p 13, paras 51-52, p A140.

[49] *Doolittle Affidavit*, p 13, para 52, p A140.

[50] *Doolittle Affidavit*, p 14, para 53, p A141.

[51] *Doolittle Affidavit*, Exhibit "L", "Chapter 3 of the IESO Market Rules issued May 1, 2023", pp 12-13, ss 2.6.2, p A385.

[52] *Tardif Affidavit*, p 11, para 36, p A1660.

[53] *Tardif Affidavit*, p 11, para 37, p A1660.

including those in attendance at the April 12, 2024 and September 4, 2024 meetings with Nexus Energy.[54] No one from the IESO, other than MACD, attended the mediation. The mediation ended after less than two hours.[55]

42. Nexus Energy accordingly proceeded to the next stage of the IESO's mandatory and costly dispute resolution process, namely this Arbitration.

PART III - STATEMENT OF ISSUES, LAW & AUTHORITIES

43. Nexus Energy challenges the lawfulness of the Notice of Non-Compliance and IESO Order on the following grounds:

(a) The IESO does not have the authority (contractual or otherwise) under the Market Rules to seek payment from Nexus Energy for "avoided congestion rents";

(b) The Notice of Non-Compliance and IESO Order were made, and underlying MACD investigation was conducted, in a way that breached the IESO's duty of fairness to Nexus Energy; and

(c) Nexus Energy reasonably relied on the IESO's representations such that MACD should be estopped from enforcing the Notice of Non-Compliance and IESO Order.

44. Each ground above is an independent and sufficient basis upon which to direct the IESO, pursuant to Chapter 3, section 2.7.25 of the Market Rules, to interpret and apply

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[54] *Tardif Affidavit*, p 11, para 38, p A1660.

[55] *Tardif Affidavit*, pp 11-12, paras 38-39, pp A1660-1661.

Chapter 3, section 6.6.10A.2 of the Market Rules such that "avoided congestion rents" are not recoverable by the IESO against Nexus Energy.[56]

Issue 1: No authority under Market Rules for "avoided congestion rents"

45. The Market Rules and Market Manuals are unilaterally drafted and issued by the IESO.[57] To participate in the IESO-administered markets, entities such as Nexus Energy are required to register as market participant.[58] To become a registered market participant, entities like Nexus Energy must sign an IESO participation agreement, which Nexus Energy did.[59] Chapter 1, subsection 4.3.1 of the Market Rules states that:

> *"The market rules have the effect of a contract between each market participant and the IESO by virtue of the execution by the IESO and each market participant of the participation agreement under which each market participant and the IESO agree to perform and observe the market rules so far as they are applicable to each market participant and the IESO as provided for in the market rules, their respective licences and applicable law."*[60] (underlining added)

46. Interpreting a standard form contract, like any other contract, requires determining the objective, mutual intentions of the parties in light of the contract as a whole and the surrounding factual matrix at the time of formation of the contract.[61] The *Sattva* approach

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[56] *Doolittle Affidavit*, Exhibit "L", "Chapter 3 of the IESO Market Rules issued May 1, 2023", pp 21-22, ss 2.7.25, pp A394-395.
[57] *Electricity Act,* ss 32(1).
[58] *Doolittle Affidavit*, Exhibit "B", "Participation Agreement between Nexus Energy and IESO signed August, 16 2017", p 2, para B, p A149.
[59] *Doolittle Affidavit*, p 2, para 4. Exhibit "B", "Participation Agreement between Nexus Energy and IESO signed August, 16 2017", pp A147-162.
[60] *Doolittle Affidavit*, Exhibit "K", "Chapter 1 of the IESO Market Rules issued June 2, 2021", p 3, ss 4.3.1, p A338.
[61] *1797472 Ontario Inc v Independent Electricity System Operator*, 2024 ONSC 2130 ["***1797472 Ontario Inc***"]; upheld on appeal at 2024 ONCA 808, para 26, citing *Sattva Capital Corp v Creston Moly Corp*, 2014 SCC 53, [2014] 2 SCR 633 ["***Sattva***"], paras. 47–48, among others.

to contractual interpretation has been specifically applied in the context of contracts with the IESO.[62]

47. The Supreme Court of Canada has clarified that in interpreting standard form agreements, the surrounding "factual matrix" specific to the contracting parties plays less of a role in the interpretive exercise, as the contract is not the product of negotiations between those specific parties.[63] However, more general contextual information still forms part of the relevant factual matrix.[64] Courts can examine "factors such as the purpose of the contract, the nature of the relationship it creates, and the market or industry in which it operates".[65] To the extent the Market Rules and Market Manuals constitute a standard form contract of adhesion, the same interpretive principles continue to apply.[66]

48. Given the nature of the Market Rules, the factual matrix is predominantly derived from the IESO's processes that created and supported them, and statements made by the IESO about them and their intended purpose.[67] The factual matrix in this case favours Nexus Energy's interpretation, i.e. any compliance or enforcement action for failed intertie transactions under Chapter 3, section 6.6.10A.2 (above and beyond IFCs and EFCs) would be limited to instances of "egregious" behaviour as described more fully below. No egregious or nefarious behaviour has been alleged against Nexus Energy in this case.

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[62] *1797472 Ontario Inc*.
[63] *1797472 Ontario* Inc, para 27, citing *Ledcor Construction Ltd v Northbridge Indemnity Insurance Co*, 2016 SCC 37 ["***Ledcor***"], paras 31-32.
[64] *1797472 Ontario Inc*, para 27, citing *Ledcor*, paras 31-32.
[65] *1797472 Ontario Inc*, para 28.
[66] *Ledcor*, paras 20, 106-109, 116.
[67] *1797472 Ontario Inc*, para 39.

49. Consistent with the principles enunciated above, the Market Rules and Market Manuals should be interpreted:

(a) as whole, in a manner that gives meaning to all of their terms and avoids an interpretation that would render one or more of their terms ineffective;

(b) by determining the intention of the parties in accordance with the language they used, based upon the cardinal presumption that they intended what was said at the time of contract;

(c) with regard to objective evidence of the factual matrix, but without reference to the subjective intention of the parties; and

(d) in a fashion that accords with sound commercial principles and good business sense, and that avoids commercial absurdity.[68]

50. The specific provisions of the Market Rules at issue must not be read in isolation and must be considered in harmony with other terms and in light of their purpose and commercial context.[69] Further, the court's interpretation should strive to give meaning and effect to all of a contract's terms (or in this case, all of the Market Rules) and avoid rendering portions meaningless and ineffective.[70]

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[68] *1797472 Ontario Inc*, p at para 29.
[69] *1797472 Ontario Inc*, p at para 30.
[70] *1797472 Ontario Inc*, para 30. After applying these principles of construction, to the extent there remains any ambiguity, that ambiguity should be construed against the IESO as drafter of the standard form contract (*contra proferentem*). *Ledcor*, paras 50-51.

51. For the reasons that follow in this section, the IESO has no authority (contractual or otherwise) under the Market Rules to assess and collect “avoided congestion rents”.

No authority by a plain reading of the Market Rules

52. The IESO relies on the following Market Rules for its authority to issue the IESO Order:

Chapter 7, sections 7.5.8A and 7.5.8B:

> *7.5.8A A registered market participant associated with a registered facility that is a boundary entity shall, other than for the bona fide and legitimate reasons referred to in section 7.5.8B, schedule energy and operating reserve, in accordance with section 6.1.3, with the appropriate scheduling entity, or scheduling entities as the case may be.*
>
> *7.5.8B The IESO may take actions pursuant to section 6.6.10A of Chapter 3 and shall assess a real-time import or export failure charge as determined in section 3.8C of Chapter 9 where a registered market participant associated with a registered facility that is a boundary entity fails to schedule energy or operating reserve, in accordance with section 6.1.3 of Chapter 7, with the appropriate scheduling entity, or scheduling entities as the case may be, according to the applicable interchange schedule, other than for bona fide and legitimate reasons as determined by the IESO. Bona fide and legitimate reasons shall include failures caused by actions and circumstances beyond the control of the market participant or due to IESO or external scheduling entity error or action, including those reasons specified in the applicable market manual.*[71] (underlining added)

And Chapter 3, section 6.6.10A:

> *6.6.10A In respect of a breach of section 7.5.8A of Chapter 7, the IESO may:*

[71] *Doolittle Affidavit*, Exhibit “M”, “Chapter 7 of the IESO Market Rules issued November 29, 2023”, pp 73-74, ss 7.5.8A-7.5.8B, pp A537-538.

> *6.6.10A.1 issue a letter of non-compliance or impose a financial penalty upon the market participant pursuant to sections 6.6.2.3, and 6.6.6; and*
>
> *6.6.10A.2 adjust settlement amounts paid or payable to a registered market participant such as transmission rights payments, congestion management settlement credits or other settlement amounts that the registered market participant received or avoided due to an act or omission or a course of conduct of either the registered market participant alone or the registered market participant by agreement or arrangement with one or more other market participants that led to the breach of section 7.5.8A of Chapter 7.*[72] (underlining added)

53. According to the Notice of Non-Compliance, each of the Subject Transactions constitutes a breach of Chapter 7, section 7.5.8A of the Market Rules.[73] The IESO Order requires payment of $2,078,824.92 for "avoided congestion rents", which the IESO automatically debited from Nexus Energy in February 2025.[74]

Other payments made by Nexus Energy not in dispute

54. In addition to the payment of $2,078,824.92 for "avoided congestion rents", which Nexus Energy disputes in this Arbitration, the IESO also assessed and collected from Nexus Energy the following charges during the same period (including for the applicable Subject Transactions) that are not being challenged by Nexus Energy in this Arbitration:

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[72] *Doolittle Affidavit*, Exhibit "L", "Chapter 3 of the IESO Market Rules issued May 1, 2023", p 77, ss 6.6.10A, p A450.

[73] *Doolittle Affidavit*, Exhibit "F", "IESO Notice of Non-Compliance dated December 17, 2024", Schedule A, p 21, para 92, p A250.

[74] *Doolittle Affidavit*, Exhibit "F", "IESO Notice of Non-Compliance dated December 17, 2024", Schedule A, p 21, para 92, p A250; Exhibit "G", "IESO invoice dated February 14, 2025", pp A252-253.

(a) $4,931.76 in transmission rights benefits, as Nexus Energy recognizes the IESO's authority to recover transmission rights payments as expressly stated in Chapter 7, section 7.5.8B of the Market Rules; and

(b) real-time import failure charges ("**IFCs**") and export failure charges ("**EFCs**") in the total amount of over $1,663,000, as Nexus Energy recognizes the IESO's authority to levy IFCs and EFCs as expressly set out in Chapter 7, section 7.5.8B.[75]

55. However, the payment of an additional $2,078,824.92 for "avoided congestion rents" is very different. There is no express authority under Chapter 7, section 7.5.8B (or otherwise) for the IESO to recover "avoided congestion rents".[76] MACD's enforcement actions against Nexus Energy in this case goes beyond those charges expressly authorized in Chapter 7, section 7.5.8, and are therefore unlawful.

No Market Rules authority for "congestion rents (ICPs) avoided"

56. There is no contractual or other authority for the IESO to charge "congestion rents (ICPs) avoided" against Nexus Energy. Among other things, the words "congestion rents (ICPs) avoided" do not even appear in Chapter 3, section 6.6.10A.2 of the Market Rules, the section relied upon by MACD to issue the IESO Order.[77]

57. In addition, and as further detailed below:

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[75] *Doolittle Affidavit*, p 8, para 31, p A135.

[76] *Doolittle Affidavit*, Exhibit "M", "Chapter 7 of the IESO Market Rules issued November 29, 2023", p 74, s 7.5.8B, p A538.

[77] *Doolittle Affidavit*, Exhibit "L", "Chapter 3 of the IESO Market Rules issued May 1, 2023", p 77, ss 6.6.10A.2, p A450.

(a) "congestion rents (ICPs)" are not a "settlement amount"; and

(b) "congestion rents (ICPs)" do not have an IESO charge code, equation or settlement amount acronym – unlike IESO settlement amounts authorized by the Market Rules.

"Congestion rents (ICPs)" are not a "settlement amount" under the Market Rules

58. MACD relies on the contractual authority under Chapter 3, section 6.6.10A.2 that gives it the authority to "adjust … other settlement amounts that the registered market participant received or avoided …".[78]

59. However, "congestion rents (ICPs)" are not a "settlement amount" under the IESO Market Rules. "[S]ettlement amount" is a defined term under Chapter 11 of the Market Rules.[79] It is defined to mean "<u>any amount of money to be paid by or to</u> a market participant, <u>determined in accordance with Chapter 9</u>" (underlining added).[80]

60. The definition of "settlement amount" does not include "avoided congestion rents" for at least two reasons (as underlined above). First, "avoided congestion rents" are not "any amount of money to be paid by or to" anyone. Because each of the Subject Transactions did not flow, Nexus Energy did not receive any revenue from, nor pay congestion rents or ICP for, the Subject Transactions. There were no monies for Nexus Energy to reimburse or return to the IESO.

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[78] *Doolittle Affidavit*, Exhibit "L", "Chapter 3 of the IESO Market Rules issued May 1, 2023", p 77, ss 6.6.10A.2, p A450.

[79] *Doolittle Affidavit*, Exhibit "O", "Chapter 11 of the IESO Market Rules issued November 29, 2023", pp A782-834.

[80] *Doolittle Affidavit*, Exhibit "O", "Chapter 11 of the IESO Market Rules issued November 29, 2023", p 38, p A827.

61. Instead, the charge by the IESO of $2,078,824.92 for "avoided congestion rents" was a payment out-of-pocket by Nexus Energy for transactions that never occurred.[81] It was not an amount that was "received or avoided" by Nexus Energy and therefore does not fall within the scope of Chapter 3, section 6.6.10.A.2.[82]

62. Second, congestion rents (or "congestion rents avoided") are not determined in accordance with Chapter 9. Rather, at best, congestion rents are mentioned as a variable or an input into the calculation of contributions to the "transmission charge reduction fund" ("**TCRF**"), as follows [underlining added]:

> *"3.6.2 The contribution to the transmission charge reduction fund in settlement hour 'h' ("TCRFh") shall be the net congestion rentals collected by the IESO (the negative of the net energy market settlement credit paid to market participants) less the net payments from the IESO to market participants under TRs, or:*

$$TCRF_h = \Sigma_{t,m} (EMP_h^{m,t} - EMP_h^{REF,t}) \times \Sigma_k (AQEW_{k,h}^{m,t} - AQEI_{k,h}^{m,t}) - \Sigma_k TRSC_{k,h}$$

where:

t = all *metering intervals* in *settlement hour* 'h'
m = all *primary* RWMs and *intertie metering points*
k = all *market participants*

> *EMPhREF,t= energy market price at the reference bus in metering interval 't' of settlement hour 'h'. Until such time that locational pricing is implemented in the IESO-administered*

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[81] *Doolittle Affidavit*, p 9, para 32, p A136.

[82] *Doolittle Affidavit*, Exhibit "L", "Chapter 3 of the IESO Market Rules issued May 1, 2023", p 77, ss 6.6.10.A.2, p A450.

> *markets, the uniform energy market price is the energy market price at the reference bus."*[83]

63. Putting aside the technical complexity of the formula, congestion rents are not calculated or determined in accordance with this section 3.6.2 nor any other section in Chapter 9 of the Market Rules. The reproduced section 3.6.2 above merely refers to "congestion rentals" collected by the IESO – it does not set out how they are calculated or determined.

64. Contrast this with the "settlement amounts" that are expressly authorized in the Market Rules, namely transmission rights payments (which the IESO has recovered from Nexus Energy and are not disputed) and congestion management settlement credits (which are also not in dispute in this case):

(a) The determination of "transmission rights payments" is explicitly and separately set out in its own section 3.6 of Chapter 9 entitled "Hourly Settlement Amounts for Transmission Rights and Charges".[84] Subsection 3.6.1 of Chapter 9 clearly states that the "TR settlement credit for market participant 'k' in settlement hour 'h' … shall … be determined by the following equation".[85] (underlining added)

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[83] *Doolittle Affidavit*, Exhibit "N", "Chapter 9 of the IESO Market Rules issued November 29, 2023", p. 47, ss 3.6.2, p A667.

[84] *Doolittle Affidavit*, Exhibit "N", "Chapter 9 of the IESO Market Rules issued November 29, 2023", pp 46-47, s 3.6, pp A666-667.

[85] *Doolittle Affidavit*, Exhibit "N", "Chapter 9 of the IESO Market Rules issued November 29, 2023", p 46, ss 3.6.1, p A666.

(b) Likewise, the determination of "congestion management settlement credits" is set out in a separate section in Chapter 9 entitled "Hourly Settlement Amounts for Congestion Management".[86] Chapter 9, subsection 3.5.2, explicitly sets out the calculation of congestion management settlement credits including using the words "… the hourly congestion management settlement credit for market participant 'k' for settlement hour 'h' … shall be determined by the following equation ….".[87] (underlining added)

65. Even the IFCs and EFCs (the levying of which is expressly authorized under Chapter 7, section 7.5.8.B as described in paragraph 52 above), are expressly stated "to be determined" in Chapter 9, as follows:

> *[Chapter 9 of the IESO Market Rules]*
>
> ***3.8C Real-Time Import and Real-Time Export Failure Charges***
>
> *The real-time import failure charge and the real-time export failure charges referred to in section 7.5.8B of Chapter 7 are settlement amounts that shall be determined in sections 3.8C.2 and 3.8C.3 and in sections 3.8C.4 and 3.8C.5 [of Chapter 9], respectively".*[88] (underlining added)

Nowhere in Chapter 9 does the same language exist for the determination of congestion rents or "congestion rents avoided" or ICP.

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[86] *Doolittle Affidavit*, Exhibit "N", "Chapter 9 of the IESO Market Rules issued November 29, 2023", p 36, s 3.5, p A656.

[87] *Doolittle Affidavit*, Exhibit "N", "Chapter 9 of the IESO Market Rules issued November 29, 2023", p 38, ss 3.5.2, p A658

[88] *Doolittle Affidavit*, Exhibit "N", "Chapter 9 of the IESO Market Rules issued November 29, 2023", p 72, ss 3.8C.1, p A692.

66. Indeed, ICP is expressly defined to be an amount that is "determined in accordance with … Chapter 7" - and not in accordance with Chapter 9 - as follows:

> *"Intertie congestion price (ICP) means, in respect of a given dispatch hour, a price equal to the projected market price for energy or operating reserve for a given intertie zone minus the projected uniform market price for energy or operating reserve respectively, in the IESO control area, determined in accordance with section 8.1.1A of Chapter 7".*[89] (underlining added)

67. For these reasons, "congestion rents (ICPs) avoided" do not meet the definition of a "settlement amount" under the IESO Market Rules and therefore cannot be sought by the IESO under Chapter 3, section 6.6.10A.2.

Congestion rents do not have an IESO charge code, equation or settlement amount acronym

68. The IESO is authorized under the Market Rules to assess and collect a wide range of charges.[90] To assist market participants, the IESO publishes a Market Manual entitled "IESO Charge Types and Equations". The stated purpose of the Market Manual is:

> *"… to provide the reader with the formulas and variable definitions behind each different charge type implemented in the IESO Settlements process including tax treatment. Furthermore, this document relates each charge type to the*

[89] *Doolittle Affidavit*, Exhibit "O", "Chapter 11 of the IESO Market Rules issued November 29, 2023", p 23, p A812.
[90] *Doolittle Affidavit*, Exhibit "N", "Chapter 9 of the IESO Market Rules issued November 29, 2023", p A615-780.

> *high-level description of the settlement amount within the IESO market rules …".*[91] (underlining added)

69. The over 300-page Market Manual lists hundreds of IESO charge types, equations and settlement amount acronyms – none of which includes a charge type, equation or settlement amount acronym for congestion rents.[92]

70. In contrast, the Market Manual does include a separate and distinct "charge type number" and "settlement amount acronym" for each of IFCs and EFCs, transmission rights, and congestion management settlement credits (as well as many other forms of expressly authorized IESO charges). Specifically:

(a) for IFCs and EFCs, the IESO charge type numbers are 135 and 136 respectively. The settlement amount acronym for IFCs is "RT-IFC". The settlement amount acronym for EFCs is "RT_EFC".[93]

(b) for transmission right payments, settlement credits are assigned IESO charge type number 104 and settlement amount acronym "TRSC".[94]

(c) for congestion management settlement credits, the IESO charge type number is 105 and the settlement amount acronym is "CMSC".[95]

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[91] *Doolittle Affidavit*, Exhibit "R", "IESO Market Manual entitled 'IESO Charge Types and Equations' dated November 29, 2023," p 1, s 1.1, p A1103.

[92] *Doolittle Affidavit*, Exhibit "R", "IESO Market Manual entitled 'IESO Charge Types and Equations' dated November 29, 2023, pp A1094-1421.

[93] *Doolittle Affidavit*, Exhibit "R", "IESO Market Manual entitled 'IESO Charge Types and Equations' dated November 29, 2023," pp 62-63, p A1164-1165.

[94] *Doolittle Affidavit*, Exhibit "R", "IESO Market Manual entitled 'IESO Charge Types and Equations' dated November 29, 2023," p 45, p A1147.

[95] *Doolittle Affidavit*, Exhibit "R", "IESO Market Manual entitled 'IESO Charge Types and Equations' dated November 29, 2023," p 47, p A1149.

71. As stated, there is no charge type, equation or settlement amount acronym for "congestion rents". While there is an equation for ICP[96], there is no charge type code number nor settlement amount acronym for ICP.

72. Accordingly, when the IESO debited from Nexus Energy the amount of $2,078,824.92 in "avoided congestion rents", the IESO did not (and could not) separately identify such charge as a reversal of any settlement amount made with an independent charge type or charge code number.

73. Instead, the IESO cited entirely different and inapplicable charge types and code numbers (1111 – Real-Time Energy Settlement Amount for Imports and 1113 - Real-Time Energy Settlement Amount for Exports[97]) and subsumed the $2,078,824.92 debit thereunder.[98] In other words, when it came time to invoice the payment, the IESO had to pick a charge type and code so picked one.

74. Read as a whole and in harmony with the rest of the Market Rules and Market Manuals, Chapter 3, section 6.6.10A does not give MACD the authority to seek payment of "congestion rents (ICP) avoided" from Nexus Energy. Accordingly, the IESO acted without lawful authority and in breach of contract. On this basis alone, the IESO should

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[96] *Doolittle Affidavit*, Exhibit "N", "Chapter 9 of the IESO Market Rules issued November 29, 2023", p 23, ss 3.1.3, p A642; Notwithstanding, here ICP is only listed as a variable or input into the determination of energy market prices and quantities. It does not displace the definition of ICP as set out in Chapter 11 of the Market Rules, namely that ICP is determined in accordance with section 8.1.1A of Chapter 7 (and not Chapter 9).

[97] *Doolittle Affidavit*, para 32, p A136; Exhibit "R", "IESO Market Manual entitled 'IESO Charge Types and Equations' dated November 29, 2023," p 115, p A1217.

[98] *Doolittle Affidavit*, Exhibit "G", "IESO invoice dated February 14, 2025", pp A252-253.

be directed to interpret and apply the Market Rules accordingly and to return the unlawfully obtained amount of $2,078,824.92 to Nexus Energy.[99]

Issue 2: IESO breached its duty of fairness to Nexus Energy

75. Fairness is a cornerstone of modern Canadian administrative law. Public decision makers are required to act fairly in coming to decisions that affect the rights, privileges or interests of an individual.[100]

76. The IESO (including MACD) is a public authority established under Part II of the *Electricity Act*[101], required to exercise its contractual authority in accordance with administrative law principles.[102] When it makes administrative decisions affecting a person's rights, privileges or interests (as it did here with Nexus Energy), the duty of fairness is triggered.[103]

77. The duty of fairness promotes sound public administration and the accountability of public decision-makers by ensuring their decisions are made with input from those affected by them.[104] Well-informed decisions are likely to be better decisions.[105]

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[99] *Doolittle Affidavit*. Exhibit "L", "Chapter 3 of the IESO Market Rules issued May 1, 2023", pp 21-22, ss 2.7.25, pp A394-395.
[100] See *Agraira v Canada (Public Safety and Emergency Preparedness)*, 2013 SCC 36 ["***Agraira***"], para 93, "[p]rocedural fairness is a cornerstone of modern Canadian administrative law. Public decision makers are required to act fairly in coming to decisions that affect the rights, privileges or interests of an individual".
[101] *Electricity Act*, s 5.
[102] *Huscroft*, p 153, p A85.
[103] *Huscroft*, p 153, p A85; see, ***e.g.***, *Baker v Canada (Minister of Citizenship and Immigration)*, 1999 CanLII 699 (SCC) ["***Baker***"], para 20, where Justice L'Heureux-Dubé explained, "[t]he fact that a decision is administrative and affects the rights, privileges, or interest of an individual is sufficient to trigger the application of the duty of fairness."
[104] *Huscroft*, p 150, p A82.
[105] *Huscroft*, p 150, p A82.

Decisions made pursuant to transparent, participatory processes promote important rule-of-law values.[106]

78. The duty of fairness is important in its own right, for it ensures that people are allowed to participate meaningfully in decision-making processes that affect them.[107] In other words, the duty protects dignitary interests by requiring that people be treated with respect.[108] Procedurally unfair decisions are quashed and remitted to be made in accordance with the required procedural protection.[109]

79. In *Baker v Canada (Minister of Citizenship and Immigration*, the Supreme Court of Canada described the duty of procedural fairness as follows:

> *"… the purpose of the participatory rights contained within the duty of procedural fairness is to ensure that administrative decisions are made using a fair and open procedure, appropriate to the decision being made and its statutory, institutional and social context, with an opportunity for those affected by the decision to put forward their views and evidence fully and have them considered by the decision-maker."*[110] (underlining added)

80. The protection afforded by the duty of fairness is necessarily flexible rather than fixed.[111] In practice, the content of the duty is informed by the context in which a particular decision is made and varies in accordance with a number of factors.[112]

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[106] *Huscroft*, p 150, p A82
[107] *Huscroft*, p 151, p A83
[108] *Huscroft*, p 151, p A83
[109] *Huscroft*, pp 151, 153 and 181-182, pp A82, 83, 113-114.
[110] *Baker*, para 22; also see *Huscroft*, p 166, p A98.
[111] *Huscroft*, p 152, p A84
[112] *Huscroft*, p 152, p A84

81. Applying the *Baker* factors to this case, a high degree of procedural fairness[113] was owed by the IESO to Nexus Energy for the following reasons:

(a) The nature of the decision being made and the process followed in making it[114]: The decision made by the IESO is quasi-judicial in nature as it involves a determination as to whether Nexus Energy breached its regulatory obligations, with the potential for significant sanctions;

(b) The importance of the decision to the individual or individuals affected[115]: The Notice of Non-Compliance and IESO Order are very important to Nexus Energy. The Notice of Non-Compliance and IESO Order not only have resulted in a significant financial sanction, but also have caused material adverse impacts to Nexus Energy's reputation and participation rights in other energy trading jurisdictions;[116]

(c) The choices of procedure made by the agency itself[117]: While the IESO has expertise within a specialized industry, that industry is heavily regulated with detailed procedures required by the Market Rules and Market Manuals published by the IESO and the IESO is bound to follow them;

(d) The legitimate expectations of the person challenging the decision[118]: Nexus Energy had a legitimate expectation that, at a minimum, the IESO

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[113] *Huscroft*, p 167, p A99.
[114] *Baker*, para 23.
[115] *Baker*, para 25.
[116] *Doolittle Affidavit*, p 14, paras 55-56, p A141.
[117] *Baker*, para 27.
[118] *Baker*, para 26.

would observe and afford Nexus Energy the procedural protections set out in applicable published and detailed Market Rules and Market Manuals.

82. With respect to this legitimate expectation factor, the Supreme Court of Canada in *Baker* also wrote that "[i]f the claimant has a legitimate expectation that a certain procedure will be followed this procedure will be required by the duty of fairness".[119] (underlining added)

83. Accordingly, a high degree of fairness was owed by the IESO in this case, including a right for Nexus Energy to fully understand the case being put against it, to meaningfully challenge the evidence relied upon by MACD, and to otherwise be heard before any decision or sanction was made against it. Nexus Energy also had a right to an independent and unbiased decisionmaker.[120]

84. Taking into account the specific context of this case, the IESO had a duty of fairness to Nexus Energy to issue any breach determination or sanction only after following a fair and open procedure, including that the Notice of Non-Compliance and IESO Order be made:

(a) by an independent and unbiased decisionmaker;

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[119] *Baker*, para 26; also see *Agraira*, paras 94, 98; and *Huscroft,* p 169, p A101.

[120] Huscroft, p 151, p A83 stating "[i]n general, the duty of fairness requires two things, both of which are modern restatements of venerable natural justice protections: (1) the right to be heard; (2) the right to an independent and impartial hearing".

(b) only after giving Nexus Energy an opportunity to exercise its participatory rights in the decision-making process (which includes knowing the case it must meet and the right to be heard); and

(c) in accordance with Nexus Energy's legitimate expectation to the procedural protections afforded to it in the Market Rules and Market Manuals.

85. In this case, MACD's conduct breached its duty of fairness to Nexus Energy by conducting its investigation and issuing its decisions, as reflected in the Notice of Alleged Breach, Notice of Non-Compliance and IESO Order, in a way that:

(a) creates an actual or a reasonable apprehension of impartiality or bias;

(b) denied Nexus Energy's participatory rights; and

(c) failed to observe certain procedural protections afforded to Nexus Energy under the Market Rules and Market Manuals.

Each of these categories of unlawful conduct is an independent and sufficient ground on which to make a finding that the IESO beached its duty of fairness to Nexus Energy.

86. These actions offended the duty of fairness and warrants an arbitral award under Chapter 3, section 2.7.25 prohibiting enforcement of the Notice of Non-Compliance and IESO Order on the basis that such prohibition would be just and reasonable, and directing the IESO to repay $2,078,824.92 to Nexus Energy.[121]

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[121] *Doolittle Affidavit*, Exhibit "L", "Chapter 3 of the IESO Market Rules issued May 1, 2023", pp 21-22, ss 2.7.25, pp A394-395.

Relevant statutory and institutional structures

OEB's Market Surveillance Panel (MSP)

87. The Ontario Energy Board ("**OEB**") is Ontario's independent regulator of the electricity (and natural gas) sectors.[122] The OEB is a public entity created under Part II of the *Ontario Energy Board Act, 1998* ("**OEB Act**").[123]

88. The OEB has a board of directors appointed by the Lieutenant Governor in Council.[124] The OEB board of directors appoints the OEB Chief Executive Officer.[125] The Chair of the OEB board of directors is accountable to the Minister of Energy and Mines for the effective delivery of the OEB's statutory mandate.[126]

89. Within the OEB, the Market Surveillance Panel ("**MSP**") is responsible for monitoring, investigating and reporting on activities and behaviour in the *IESO-administered markets*.[127] The members of the MSP are appointed by the OEB board of directors.[128]

90. The MSP's specific responsibilities include monitoring activities and behaviour and recommending remedial action; investigating market activities and the behaviour of specific energy companies or energy-related agencies and making recommendations related to the results of its investigations; and reporting on the results of its monitoring

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[122] *Tardif Affidavit*, Exhibit "J", "Ontario Energy Board 'Who We Are' webpage", pp A1720-1721.
[123] *Ontario Energy Board Act*, 1998, SO 1998, c 15, Sch B ["***OEB Act***"], s 4(1)
[124] *OEB Act*, s 4.1(1).
[125] *OEB Act*, s 4.2(1).
[126] *Tardif Affidavit*, Exhibit "J", "Ontario Energy Board 'Who We Are' webpage", pp A1720-1721.
[127] *Tardif Affidavit*, Exhibit "K", "Ontario Energy Board 'Market surveillance panel' webpage", pp A1723-1726.
[128] *OEB Act*, s 4.3.1(2).

and investigations.[129] The MSP's monitoring activities also include identifying activities of the IESO that may have an impact on market efficiencies or effective competition.[130]

91. The OEB Act provides that, subject to the by-laws made under section 4.10 thereof, the MSP may use the services of employees of the OEB and the IESO.[131] One of the by-laws made under section 4.10 [132] is entitled "OEB By-Law #2: Market Surveillance Panel" ("**OEB By-Law #2**").[133]

92. OEB By-Law #2 entails a protocol between the OEB and the IESO entitled the "Protocol Relating to Market Surveillance Panel" last amended on May 1, 2017 ("**Protocol**").[134] The Protocol states that the MSP was transferred from the IESO to the OEB effective January 1, 2005.[135]

93. MSP members are required to comply with confidentiality protocols (including the Protocol) regarding the confidentiality and security of records, data handling and communications.[136]

IESO's Market Assessment Unit (MAU)

94. Within the IESO, and more specifically within MACD, there is a market assessment unit ("**MAU**") responsible for collecting and storing market surveillance data.[137] This

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[129] *Tardif Affidavit*, Exhibit "K", "Ontario Energy Board 'Market surveillance panel' webpage", pp A1723-1726.
[130] *Tardif Affidavit*, Exhibit "L", "Ontario Energy Board By-Law 2", p 9, ss 4.1.1(b), p A1736.
[131] *OEB Act*, s 4.3.1(5).
[132] *OEB Act*, ss 4.10(2)(j).
[133] *Tardif Affidavit*, Exhibit "L", "Ontario Energy Board By-Law 2", pp 79-95, pp A1728-1745.
[134] *Tardif Affidavit*, Exhibit "M", "OEB and IESO Protocol dated April 25, 2005", pp 96-115, pp A1747-1765.
[135] *Tardif Affidavit*, Exhibit "M", "OEB and IESO Protocol dated April 25, 2005", p 1, p A1747; Exhibit "K", "Ontario Energy Board 'Market surveillance panel' webpage", pp A1724-1725.
[136] *Tardif Affidavit*, Exhibit "L", "Ontario Energy Board By-Law 2", pp 16-17, ss 8.2.1, pp A1743-1744.
[137] *Tardif Affidavit*, Exhibit L", "Ontario Energy Board By-Law 2", p 2, ss 1.1.1, p A1729.

market surveillance data is used by the IESO and MACD to monitor activities and market participant conduct in the IESO-administered markets.[138] The IESO's failure to ensure the independence of the MAU from the rest of MACD is at the heart of the creation of actual or a reasonable apprehension of bias or impartiality in this case.

95. Under OEB By-Law #2, the OEB's MSP is permitted to use the services of the IESO's MAU.[139] In this way, the IESO's market surveillance data and MAU's analysis thereof are used by the OEB's MSP to assess market activity and market participant conduct.[140]

96. The Protocol states that the IESO's MAU "shall (a) take direction exclusively from the MSP; (b) be under the exclusive supervision of the MSP; and (c) … report exclusively and directly to the MSP" [141] (underlining added). Consistent with the contractual force of the Market Rules (discussed above), the Protocol states that it "constitutes a legal and binding obligation on the IESO, enforceable against the IESO in accordance with its terms".[142]

97. The Protocol also states in part that the IESO's MAU shall not, without the prior concurrence of the OEB's MSP:

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[138] *Tardif Affidavit*, Exhibit "K", "Ontario Energy Board 'Market surveillance panel' webpage", pp A1724-1726.

[139] *Tardif Affidavit*, Exhibit "L", "Ontario Energy Board By-Law 2", p 2, ss 1.1.1, p A1729.

[140] *Tardif Affidavit*, Exhibit "K", "Ontario Energy Board 'Market surveillance panel' webpage", pp A1724-1726.

[141] *Tardif Affidavit*, Exhibit "M", "OEB and IESO Protocol dated April 25, 2005", p 6, ss 2.2.6, p A1752. This exclusivity extends to all matters pertaining to the conduct of MSP related activities, but does not limit the ability of the IESO to direct, supervise or receive reports from MAU staff in relation to non-MSP related activities or to address administrative, human resource or employment matters of MAU staff.

[142] *Tardif Affidavit*, Exhibit "M", "OEB and IESO Protocol dated April 25, 2005", p 12, ss 5.1.1(e), p A1759.

(a) discuss its work in relation to MSP investigations;

(b) provide copies of any reports or other documents that it prepares in relation to MSP activities; nor

(c) disclose any confidential information provided to it by the MSP;[143]

with any IESO representative (which includes Glenn McDonald and Bob Yeoman)[144].

98. In short, and to preserve the confidentiality of MSP market monitoring activities, the MSP-related activities of MAU staff are required to remain independent of the rest of MACD, and MAU staff are required to report directly to the MSP with respect to MSP-related activities. By all accounts, these requirements were ignored in this case.

MACD structure creates an actual or a reasonable apprehension of bias or impartiality

99. Surprisingly, Bob Yeoman is the Director of both MACD's Market Rule compliance business unit (aka "Rule Compliance") and the MAU (aka "Market Surveillance").[145]

100. Contrary to the requirements of OEB By-law #2 and the Protocol, it appears to Nexus Energy that Bob Yeoman in his capacity as the Director of both Rule Compliance and Market Surveillance unlawfully receives information from the MAU pertaining to MSP-related activities.[146]

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[143] *Tardif Affidavit*, Exhibit "M", "OEB and IESO Protocol dated April 25, 2005", p 7, ss 2.3.1, p A1753.
[144] *Tardif Affidavit*, Exhibit "M", "OEB and IESO Protocol dated April 25, 2005", p 3, ss 1.1.1, p A1749.
[145] *Doolittle Affidavit*, Exhibit "F", "IESO Notice of Non-Compliance dated December 17, 2024", p 3, p A229.
[146] *Tardif Affidavit*, para 45, Exhibit "G", "IESO corporate organization charts", p 2, p A1696.

101. Likewise, and again contrary to OEB By-law #2 and the Protocol, it appears to Nexus Energy that Glenn McDonald in his capacity as Vice-President of MACD and direct supervisor of Bob Yeoman unlawfully receives information and documentation pertaining to MSP-related activities.[147]

102. The extent to which MSP-related information was shared between Bob Yeoman and Glenn McDonald in preparing the Notice of Alleged Breach (including the sanction assessment), the Notice of Non-Compliance and the IESO Order is not clear and very concerning. Ultimately, it creates a fundamental lack of transparency as to whether the decisions made against Nexus Energy in this case were made by the IESO/MACD completely independent of the MSP/MAU as required under the OEB By-Law #2 and Protocol. This calls into question the impartiality and fairness of the process and, frankly, the quality of the decision-making.[148]

Nexus Energy was deprived of its participatory rights in MACD's decision-making process

103. The IESO's failure to ensure procedural fairness in this case is further perpetuated by MACD having already assessed the quantum of "avoided congestion rents" when it issued the Notice of Alleged Breach.[149]

104. Such sanction assessment was premature given that Nexus Energy had not yet been given the opportunity to present <u>any</u> information or documentation to MACD in

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[147] *Tardif Affidavit*, para 45, Exhibit "G", "IESO corporate organization charts", p 2, p A1696.

[148] *Huscroft*, p 180, p A112: "[i]t is well established that the requirements of the duty of fairness are independent of the merits of the substantive matter in issue and that breach of the duty [of fairness] voids a decision".

[149] *Doolittle Affidavit,* Exhibit "C", "IESO Notice of Alleged Breach dated April 4, 2024," p 2, para 8, p A165.

response to the Notice of Alleged Breach. It is only after the consideration of any such information or documentation from Nexus Energy that MACD is then permitted under the Market Rules to determine whether a compliance breach has occurred and to assess sanctions:[150]

> *6.2.4 Following expiry of the time noted in section 6.2.3.4 [the time within which the market participant may make written representations in response to the allegations], and after consideration of any representations made by the market participant pursuant to that section, the IESO may:*
>
> *6.2.4.1 determine that the market participant has not breached the market rules;*
>
> *6.2.4.2 subject to section 6.2.5, determinate that the market participant is in breach of the market rules;*
>
> *6.2.4.3 request that the market participant provide further information in relation to the alleged breach; or*
>
> *6.2.4.4 conduct such further investigation into the matter as the IESO determines appropriate.*
>
> *6.2.5 Where a market participant has requested a meeting pursuant to section 6.2.3.5, the IESO shall provide the market participant with a reasonable opportunity to meet with the IESO to discuss the allegations. In such case the IESO shall not make the determination noted in section 6.2.4.2 until such reasonable opportunity has been given.* [151] (underlining added)

105. In this case, Nexus Energy immediately requested a meeting with MACD to discuss the Notice of Alleged Breach – which meeting took place eight days later on April 12, 2025.[152] But by April 4, 2025, MACD had already decided on quantum – without first

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[150] *Doolittle Affidavit*, Exhibit "L", "Chapter 3 of the IESO Market Rules issued May 1, 2023", pp 59-60, ss 6.2.4 and 6.2.7, pp A432-433.

[151] *Doolittle Affidavit*, Exhibit "L", "Chapter 3 of the IESO Market Rules issued May 1, 2023", pp 59-60, ss 6.6.2.4-6.6.2.5, pp A432-433.

[152] *Tardif Affidavit*, p 7, para 20, p A1656.

giving Nexus Energy an opportunity to challenge the nature and number of alleged Subject Transactions.[153]

106. Although Chapter 3, section 6.2.3.3. provides that IESO must provide the "details of the sanctions which may be imposed if the breach is established"[154], this must be limited to the type or category of sanction(s) (i.e. imposition of additional or more stringent record-keeping or reporting requirements, non-compliance letter, settlement amount readjustments, financial penalties, etc.) and should not yet include a decision on quantum. Nexus Energy had not yet received particulars or disclosure of the evidence against it, nor had Nexus Energy been given an opportunity to respond to the case against it.

107. In other words, and contrary to Nexus Energy's procedural fairness rights, MACD effectively pre-determined that Nexus Energy had committed over 1,658 market rule breaches and pre-determined a financial sanction of over $2 million.[155]

108. Notice is the most basic aspect of the duty of fairness.[156] Notice must be adequate in all circumstances in order to afford to those concerned a reasonable opportunity to present proofs and arguments, and to response to those presented in opposition.[157] The requirement to provide notice is an ongoing duty: it arises prior to the making of a decision and continues throughout the course of a decision-making process.[158]

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[153] *Doolittle Affidavit,* Exhibit "C", "IESO Notice of Alleged Breach dated April 4, 2024," p 2, para 8, p A165.
[154] *Doolittle Affidavit*, Exhibit "L", "Chapter 3 of the IESO Market Rules issued May 1, 2023", p 59, ss 6.2.3.3, p A432.
[155] *Doolittle Affidavit,* Exhibit "C", "IESO Notice of Alleged Breach dated Nexus Energy on April 4, 2024," p 2, para 8, p A165.
[156] *Huscroft*, p 171, p A103.
[157] *Huscroft*, p 171, p A103.
[158] *Huscroft*, pp 171-172, pp A103-104.

109. Having already made a preliminary sanction assessment against Nexus Energy in the Notice of Alleged Breach before giving Nexus Energy an opportunity to make representations[159], Nexus Energy was deprived its fundamental right to have its views and evidence considered as part of MACD's decision-making process.[160]

110. Ultimately, MACD failed to provide to Nexus Energy much of the evidence listed in paragraph 13 of the Notice of Alleged Breach.[161] When Nexus Energy requested further relevant information and evidence, MACD refused much of it on the basis that it would be "too burdensome" for MACD.[162]

111. In failing to provide to Nexus Energy all of the evidence listed at paragraph 13 of the Notice of Alleged Breach and in failing to respond to certain of Nexus Energy's information requests, the IESO effectively limited Nexus Energy's ability to make responding representations for the IESO's consideration as required under Chapter 3, sections 6.2.4 and 6.2.5 of the Market Rules (reproduced at paragraph 104 above).

112. Procedural breaches of this nature do not merely call into question the fairness, impartiality and independence of the decision. They also undermine the quality and integrity of the decision. Nexus Energy was deprived of the opportunity to view and test the evidence against it, and to respond accordingly.

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[159] *Doolittle Affidavit,* Exhibit "C", "IESO Notice of Alleged Breach dated April 4, 2024," p 2, paras 7-8, p A165

[160] *Huscroft*, p 166, p A98.

[161] *Tardif Affidavit*, pp 2-3, para 4, pp A1651-1652.

[162] *Tardif Affidavit*, p 8, para 23, p A1657.

MACD deprived Nexus Energy of procedural protections afforded under the Market Rules and Market Manuals

113. As the Supreme Court of Canada held in *Baker,* fairness can also be assessed according to legitimate expectations.[163] Here, Nexus Energy had a legitimate expectation that MACD would conduct its investigation and exercise its enforcement authority in accordance with governing legislative, regulatory and contractual [164] requirements including the Market Rules and Market Manuals.

114. Not only did the Notice of Alleged Breach, Notice of Non-Compliance and IESO Order fail to observe provisions of the OEB Act, OEB By-Law #2 and the Protocol (for the reasons discussed above), but they were also issued contrary to the governing Market Rules and Market Manuals.

115. Where an alleged breach is assessed as having a relatively low impact on the market or system and/or the alleged breach is committed by a new market participant or one with a good compliance history, IESO assures market participants that MACD will first issue a "Market Rule Reminder".[165] A Market Rule Reminder "serves as notice to the party of the obligation and that continued or future non-compliance will likely be subject to investigation and sanction".[166]

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[163] *Baker*, para 26;
[164] Breach of contract by the IESO is addressed directly under Issue 1, but it is also relevant to procedural fairness and legitimate expectations under Issue 2.
[165] *Doolittle Affidavit*, Exhibit "P", "IESO Market Manual 2.6: Treatment of Compliance Issues dated September 11, 2023", p 4, ss 1.3.2, p A848.
[166] *Doolittle Affidavit*, Exhibit "P", "IESO Market Manual 2.6: Treatment of Compliance Issues dated September 11, 2023", p 4, ss 1.3.2, p A848.

116. Similarly, a "Request for Information" is expressly required under IESO Market Manual 2.6 before issuing the Notice of Alleged Breach:

> *"… MACD will send the market participant or the IESO an informal "Request for Information" prior to issuing a "Notice of Alleged Breach". This assists MACD in understanding the facts and may lead to a case being closed or handling it through a "Market Rule Reminder". It may also provide better grounding for MACD to proceed formally by issuing a written "Notice of Alleged Breach".*[167]

117. The IESO failed to take these preliminary steps at any time in the preceding six years that the Subject Transactions took place. Instead, as stated, MACD jumped immediately to issuing a Notice of Alleged Breach with a sanction assessment.

118. Likewise, the Notice of Non-Compliance does not comport with the requirements under the IESO Market Rules. As mentioned, the Notice of Non-Compliance fails to include either the *level of non-compliance*[168] or the *rate of recurrence of non-compliance*[169] both of which the IESO is required to determine pursuant to Chapter 3, section 6.6 of the Market Rules. The level of detail in the published requirement is notable:

(a) Section 6.6.3 expressly sets out a tiered determination of the level of non-compliance. [170]

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[167] *Doolittle Affidavit*, Exhibit "P", "IESO Market Manual 2.6: Treatment of Compliance Issues dated September 11, 2023", p 4, ss 1.3.2, p A848.

[168] *Doolittle Affidavit*, Exhibit "L", "Chapter 3 of the IESO Market Rules issued November 29, 2023", p 71, ss 6.6.2.1, p A444.

[169] *Doolittle Affidavit*, Exhibit "L", "Chapter 3 of the IESO Market Rules issued November 29, 2023", p 71, ss 6.6.2.2, p A444.

[170] *Doolittle Affidavit*, Exhibit "L", "Chapter 3 of the IESO Market Rules issued November 29, 2023", pp 72-73, ss 6.6.3, pp A445-446.

(b) Section 6.6.4 provides that the "IESO shall determine the rate of recurrence of non-compliance referred to in section 6.6.2.2 based on the frequency and duration with which the market participant has been found by the IESO to be in breach of the market rules".[171]

119. The IESO failed to include any aspect of those requirements in the Notice of Non-Compliance.[172]

120. Because the Notice of Alleged Breach and the Notice of Non-Compliance failed to comply with the governing statutory framework (i.e. the OEB Act, OEB By-Law #2 and the Protocol) and contractual framework (i.e. the Market Rules and Market Manuals), Nexus Energy was deprived of procedural protections to which it had a legitimate expectation and entitlement under the duty of fairness.[173]

121. Fairness is a minimum duty that must be met – it is a floor for procedural protection rather than a ceiling.[174] MACD's conduct in this case simply falls short of the minimum standard of fairness required by a public sector regulator. The way in which MACD conducted its investigation and sanction assessment denied Nexus Energy its right to an open and fair administrative decision-making process. It was also contrary to Nexus Energy's legitimate expectations. All aspects of both the decision-making process and the decisions themselves are thereby undermined.[175]

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[171] *Doolittle Affidavit*, Exhibit "L", "Chapter 3 of the IESO Market Rules issued November 29, 2023", p 73, ss 6.6.4, p A446
[172] *Doolittle Affidavit*, Exhibit "F". "IESO Notice of Non-Compliance dated December 17, 2024", pp A227-250.
[173] *Huscroft*, p 169, p A101; see *Agraira*, paras 93-95 and 98.
[174] *Huscroft*, p 162, p A94.
[175] *Huscroft*, p 180, p A112.

122. Nexus Energy submits that it would therefore be just and reasonable to issue an arbitral award prohibiting enforcement of the Notice of Non-Compliance and IESO Order in this case, and to direct the IESO to return the sum of $2,078,824.92 to Nexus Energy forthwith.[176]

Issue 3: IESO/MACD should be estopped from enforcing the Notice of Non-Compliance and IESO Order

123. In the alternative, even if it is determined that MACD has the contractual or other authority to issue the Notice of Non-Compliance and IESO Order (which is denied), and it is also determined the IESO complied with its duty of fairness (which is denied), the IESO should be estopped from enforcement against Nexus Energy in this case. Here, both estoppel by representation and estoppel by silence/inaction apply.

124. Estoppel by representation is an equitable defence that may be raised in the face of regulatory violations alleged by public officials.[177] While estoppel in a public law context admittedly has narrow application, it is still applicable so long as it is not inconsistent with a statutory provision.[178]

125. Estoppel by representation requires a positive representation made by a party whom it is sought to bind (in this case the IESO/MACD), with the intention that it shall be acted on by the party with whom he or she is dealing (market participants such as Nexus Energy), the latter having so acted upon it as to make it unjust or inequitable that the party

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[176] *Doolittle Affidavit*. Exhibit "L", "Chapter 3 of the IESO Market Rules issued May 1, 2023", pp 21-22, ss 2.7.25, pp A394-395.
[177] *Abbott v Canada (T.D.),* 2001 FCT 242 at para 70 ["***Abbott***"]; dismissed on different grounds at (2005) FC 163; leave to Supreme Court of Canada denied at 2007 CanLII 16775 (SCC).
[178] *Abbott* at para 70.

making the representation should be permitted to dispute its truth, or do anything inconsistent with it.[179]

126. Estoppel by representation can also arise from silence or inaction if a legal duty is owed by the representor (here, IESO/MACD) to the representee (Nexus Energy) to make a disclosure, or take steps, the omission of which is relied upon as creating an estoppel.[180]

127. Detrimental reliance lies at the heart of true estoppel.[181] Detrimental reliance encompasses two distinct but interrelated concepts: reliance and detriment.[182] Reliance requires a finding that the party seeking to establish the estoppel changed its conduct by acting or abstaining from acting in reliance upon the assumption, thereby altering its legal position. If this reliance threshold is met then, should the other party be allowed to abandon the assumption, detriment must be suffered by the estoppel-raiser because of the change from its assumed position.[183]

Estoppel based on representations in 2005 MACD Report and 2006 Market Rule Amendments

128. The IESO's approach toward Nexus Energy in this case runs contrary to public representations made by the IESO and MACD to stakeholders starting almost 20 years ago – which representations Nexus Energy relied on to its detriment when it decided to sign the participation agreement with the IESO in 2017 to join the IESO-administered markets and to structure its operations and trading activities in Ontario.

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[179] *Ryan v Moore*, 2005 SCC 38, para 5 ["***Ryan***"]. Also see *Abbott* at para 69.
[180] *Ryan*, para 76.
[181] *Ryan*, para 68.
[182] *Ryan*, para 69.
[183] *Ryan*, para 69.

129. On November 18, 2005, MACD issued a report entitled "Intertie Transactions Failures Guidance" ("**MACD Report**").[184] According to the MACD Report, the IESO's (then) general approach to intertie transaction failures was for MACD to commence a Market Rules compliance investigation against the relevant market participant (as MACD has done against Nexus Energy in this dispute).[185]

130. One of the main proposals in the MACD Report was to change this approach – that is, to stop treating transaction failures as compliance issues to be investigated by MACD, and instead to impose an automated "settlement charge for their failed transactions deemed within their control", i.e. IFCs and EFCs.[186]

131. More specifically, the MACD Report recommended narrowing the category of compliance issues (which would attract potential enforcement action above and beyond automated settlement charges) to those transaction failures associated with "egregious behavior":

> *"The second, more fundamental proposal, is to no longer treat transaction failures as a compliance matter, except where there appears to be egregious behaviour. Rather, as part of the settlement process, a market participant would compensate the market for transaction failures that are deemed to be under its control. This would require a [market] rule change to remove the formula-based penalty. Potential egregious conduct associated with transaction failures would lead to the normal [MACD] compliance investigation if it is alleged that the market participant unfairly benefitted from*

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[184] *Doolittle Affidavit*, Exhibit "I", "IESO report entitled 'Intertie Transaction Failure Guidelines' dated November 18, 2005", pp A280-294.

[185] *Doolittle Affidavit*, Exhibit "I", "IESO report entitled 'Intertie Transaction Failure Guidelines' dated November 18, 2005", p 10, p A289.

[186] *Doolittle Affidavit*, Exhibit "I", "IESO report entitled 'Intertie Transaction Failure Guidelines' dated November 18, 2005", p 11, p A290.

> *transmission rights payments, CMSC or other revenues.*[187] (underlining added)
>
> . . . . .
>
> *The attractiveness of the settlement proposal is that it would remove the stigma associated with market rule breaches and the related administrative burden on market participants and MACD in reviewing and remedying alleged breaches."*[188]

132. The MACD Report specifically warned against imposing the more stringent regulatory approach that has been followed against Nexus Energy in this case:

> "*The risk of a significantly more stringent regulatory approach is that it may lower transaction failures but at the cost of lost trade. MACD joins with the majority of working group members who support developing a more market-oriented approach to addressing transaction failures, as along the lines of what is outlined above."*[189]

133. MACD's proposed approach was ultimately brought to the IESO board of directors for approval in January 2006, by way of a package of Market Rule amendment proposals (MR-00308-R00 through MR-00308-R04) ("**Market Rule Amendments**").[190]

134. Among other things, the Market Rule Amendments introduced automated IFCs and EFCs. The summary section of the Market Rule Amendments states in part that (underlining added):

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[187] *Doolittle Affidavit*, Exhibit "I", "IESO report entitled 'Intertie Transaction Failure Guidelines' dated November 18, 2005", p 10, p A289.
[188] *Doolittle Affidavit*, Exhibit "I", "IESO report entitled 'Intertie Transaction Failure Guidelines' dated November 18, 2005", p 11, p A290.
[189] *Doolittle Affidavit*, Exhibit "I", "IESO report entitled 'Intertie Transaction Failure Guidelines' dated November 18, 2005", pp 11-12, pp A290-291.
[190] *Doolittle Affidavit*, Exhibit "J", "IESO's 2006 Market Rule Amendment Proposals: MR-00308-R00 to MR-00308-R04", pp A296-326.

"It is proposed to amend the market rules to no longer treat intertie transaction failures as a compliance matter, except in the case of egregious behaviour. Instead, it is proposed that as part of the settlement process, the market participant would be assessed a new charge, called an "import/export failure charge", that would compensate the market for intertie transaction failures that fail for reasons that are not "bona fide and legitimate" (which as defined in the market rules largely include reasons that are beyond the control of the market participant). Where a transaction fails for bona fide and legitimate reasons, the failure charge would not be assessed. However, where egregious behaviour has occurred, the amended compliance rules would allow compliance actions to be taken to recover settlement amounts (such as transmission rights payments, congestion management settlement credits or other settlement amounts) that were made to the market participant as a result of that behaviour. (underlining added)

. . . . . .

Amendments are proposed to the compliance provisions in Chapter 3, to the provisions relating to compliance with dispatch instructions in Chapter 7, to a provision relating to the transmission rights clearing account in Chapter 8, and to the settlement provisions of Chapter 9.

The compliance provisions of Chapter 3 would be amended to remove the present formulaic penalty provision. This would be replaced by an import/export failure charge that is separate from the compliance construct of Chapter 3. This settlement provision would have market participants compensate the market for deviations from their intertie transaction schedules. For circumstances of egregious behaviour where payment recovery is appropriate and presently made through the formula based penalty, a specific provision would be added to enable the adjustment of settlement amounts. Chapter 7, section 7.5.8B, Compliance with Dispatch Instructions would be amended to allow for the application of the new settlement provisions. Chapter 8, section 4.18 would be amended to allow for the return to the transmission rights clearing account of payments that were inappropriately paid to a market participant."[191] (underlining added)

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[191] *Doolittle Affidavit*, Exhibit "J", "IESO's 2006 Market Rule Amendment Proposals: MR-00308-R00 to MR-00308-R04", p 2, p A297.

135. The Market Rule Amendments were approved by the IESO Board of Directors on or about February 7, 2006.[192] The Market Rule Amendments, including the implementation of IFCs and EFCs, became effective June 1, 2006.[193] This entailed explicitly including IFCs and EFCs in Chapter 7, section 7.5.8A of the Market Rules.[194]

136. The public and published statements listed above more than satisfy the requirement for positive representations to ground this form of equitable estoppel.

Nexus Energy reasonably relied on the IESO's representations

137. The Market Rule Amendments also included Chapter 9, section 3.8C.1 (reproduced above) which states that the "real-time import failure charge and the real-time export failure charges referred to in section 7.5.8B of Chapter 7 are settlement amounts that shall be determined in accordance with sections 3.8C.2 and 3.8C.3 and in sections 3.8C.4 and 3.8C.5, respectively".[195] (underlining added)

138. Based on the language in the Market Rule Amendments, it was reasonable for market participants like Nexus Energy to conclude that IFCs and EFCs would be the mechanism by which failed intertie transactions would be addressed by the IESO on a

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[192] *Doolittle Affidavit*, Exhibit "J", "IESO's 2006 Market Rule Amendment Proposals: MR-00308-R00 to MR-00308-R04", p 1, p A296.

[193] *Doolittle Affidavit*, Exhibit "J", "IESO's 2006 Market Rule Amendment Proposals: MR-00308-R00 to MR-00308-R04", p 1, p A296.

[194] *Doolittle Affidavit*, Exhibit "J", "IESO's 2006 Market Rule Amendment Proposals: MR-00308-R00 to MR-00308-R04", p 13, p A308.

[195] *Doolittle Affidavit*, Exhibit "J", "IESO's 2006 Market Rule Amendment Proposals: MR-00308-R00 to MR-00308-R04", p 23, p A318.

go-forward basis, and that MACD compliance investigations for failed intertie transactions would be conducted only where there is "egregious" behaviour.[196]

139. Indeed, the understanding of Nexus Energy specifically and the industry generally[197] was buttressed by MACD not taking any compliance action for failed intertie transactions (absent egregious behaviour) for almost 15 years!

140. Nexus Energy relied on the IESO's representations (in the form of the MACD Report and resulting Market Rule Amendments) and the fact that there was (to Nexus Energy's knowledge) no compliance or enforcement action taken by MACD for failed intertie transactions since at least 2006, when it made the decision to join the IESO-administered markets in December 2017 and have its energy traders determine trading offers/bids accordingly.[198]

141. Had Nexus Energy been made aware that MACD could seek payment of "avoided congestion rents" for intertie transactions that failed for non-nefarious reasons, Nexus Energy traders would have changed their bidding strategies to account for this potential liability.[199] Part of the analysis that its energy traders would have undertaken in determining whether to place an intertie trade would have incorporated the cost of "avoided congestion rent" risk where the transaction could fail.[200] For example, its energy

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[196] *Doolittle Affidavit*, p 7, para 27, p A134; *Francois Tardif Affidavit*, p 5, para 14, p A1654.

[197] Memorial of the Applicant, Tab 3, Affidavit of Giuseppe Rosati dated October 30 2025 ["***Rosati Affidavit***"], pp A2004-2006.

[198] *Tardif Affidavit*, p 6, para 17, p A1655.

[199] *Tardif Affidavit*, p 6, para 17, p A1655.

[200] *Tardif Affidavit*, p 6, para 17, p A1655.

traders would have elected not to submit bids/offers for some or many of the Subject Transactions, in whole or in part.[201]

142. That Nexus Energy's reliance was reasonable in the circumstances is further evidenced by more recent public representations made by the IESO. For instance, in an April 2024 public stakeholder engagement slide deck (and notably after the 2019 to 2021 investigation summaries were published on the IESO's public website), the IESO proposed changes to how certain failed intertie transactions are treated, namely to apply an "OTH" code and levy an IFC or EFC.[202]

143. Nowhere in this IESO slide deck from April 2024 does it state that market participants could become separately liable for "avoided congestion rents" pertaining to failed intertie transactions – that is, other than by way of IFCs and EFCs.[203]

144. This is consistent with IESO Market Manual 5.5 dated March 6, 2024, which reads as follows:

> *"The market rules no longer treat intertie transaction failures as solely a compliance matter. You will be assessed a settlement charge for import and export failures to compensate the market for intertie transactions that fail for reasons that are within your control, i.e. not "bona fide and legitimate". The market rules allow for compliance actions which may include both imposing a financial penalty or recovering any settlement amount (such as transmission rights payments, congestion management settlement credits or other settlement amounts) that were inappropriately gained or avoided by a market participant. When intertie transaction*

[201] *Tardif Affidavit*, pp 6-7, para 19, p A1655-1656.

[202] *Doolittle Affidavit*, Exhibit "S", "IESO stakeholder engagement slide deck dated May 22, 2024", p 13, p A1435.

[203] *Doolittle Affidavit*, Exhibit "S", "IESO stakeholder engagement slide deck dated May 22, 2024", pp A1423-1439.

> *failures are for bona fide legitimate reasons, you are exempt from failure charges."*[204] (underlining added)

Once again, there is no express mention of "avoided congestion rents", nor is there any express mention of other recoverable "settlement amounts" other than transmission rights (TR) payments and congestion management settlement credits (CMSC) – which are already addressed above.

145. IFCs and EFCs, including the formulae used to calculate them, are also set out in the IESO's training manual entitled "Interjurisdictional Energy Trading".[205] Like the Market Rules and Market Manuals, nowhere in the training manual does it state the IESO may seek to recover "avoided congestion rents" in addition to IFCs and EFCs (as is being attempted against Nexus Energy in this case).

146. For these reasons, Nexus Energy reasonably and detrimentally relied on the IESO/MACD's representations that any compliance or enforcement action for failed intertie transactions (above and beyond the automated IFCs and EFCs that were incorporated into the Market Rules effective June 1, 2006) would be limited to instances of "egregious" behaviour. No such egregious or nefarious behaviour has been alleged against Nexus Energy in this case.

147. As such, the IESO/MACD should be estopped from effectively reversing course from the enforcement approach for failed intertie transactions after almost 15 years.

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[204] *Doolittle Affidavit*, Exhibit "Q", "IESO Market Manual 5.5: Physical Markets Settlement Amounts dated March 6, 2024", p 25, s 1.6.10, p A964.
[205] *Doolittle Affidavit*, Exhibit "T", "IESO Interjurisdictional Energy Trading training guide dated January 2014", pp 66-69, s 11, pp A1508-1511.

148. Indeed, it was not until the implementation of the IESO's Market Renewal Program in May 2025 that congestion rents became included in the formulae for calculating IFCs and EFCs.[206] As part of its Market Renewal Program stakeholder engagement, the IESO publicly presented to market participants that congestion rents would begin to be included in IFCs and EFCs effective on or about May 1, 2025.[207]

149. The IESO's inclusion of congestion rents in IFCs and EFCs is a direct response to one of the MSP's bi-annual monitoring report on activities and behaviour in the IESO-administered markets. Specifically, the MSP's Monitoring Report published in May 2017 recommended that:

> *"The IESO should revise the methodology used to set the intertie failure charge to include the congestion rents that an intertie trader avoids when it fails a scheduled transaction for reasons within its control."*[208]

150. The IESO agreed with the MSP's recommendation, responding as follows in the March 2018 MSP Monitoring Report:

> *"The IESO agrees with the [MSP's] recommendation on intertie transaction failures; an intertie trader should not benefit by avoiding congestion rents when failing intertie transactions for reasons within its own control. Market Rules are in place that allow for the recovery of congestion rents that have been avoided, or Transmission Rights payments, when the intertie trader fails its transactions for illegitimate reasons. The IESO will consider the structure of intertie failure charges*

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[206] *Doolittle Affidavit*, Exhibit "V", "IESO Interjurisdictional Energy Trading training guide dated May 2025", pp 27-33, s 8, pp A1614-1620.
[207] *Doolittle Affidavit*, Exhibit "U", "IESO Preparing for the Launch of the Renewed Market - Intertie Traders and Transmission Rights Auction Participants presentation dated April 10, 2025", p 9, p A1525.
[208] *Tardif*, Exhibit "O", "OEB Market Surveillance Panel report dated May 2017", p 8, p A1823.

in 2017 and determine an appropriate avenue to address the issue identified by the [MSP].”[209] (underlining added)

151. Also in the March 2018 Monitoring Report, the MSP stated that it “believes the optimal solution would be one that prevents these inappropriate outcomes from arising in the first instance, rather than relying on after-the-fact payment recoveries or compliance actions”.[210]

152. Notwithstanding that this recommendation was made by the MSP over eight years ago in 2017, it was not until the implementation of the Market Renewal Project in May 2025 that the IESO revised the methodology and announced to the market that intertie failure charges would include congestion rents on a go forward basis.”[211] This was long after the Subject Transactions (December 2017 to December 2023) at issue in this proceeding.

153. For clarity, any attempt by the IESO today to rely on the MSP’s May 2017 report and/or the IESO’s March 2018 response for a purported authority to seek payment for “avoided congestion rents”, should be rejected. First, simply stating that it has such authority does not make it so – any actual authority must be rooted in law (legislation or the Market Rules). Second, a plain reading of these passages within the factual context and history of the MACD Report and Market Rules Amendments would lead a market participant like Nexus Energy to reasonably conclude that the “recovery of congestion rents” would only be pursued in instances of egregious (blameworthy) behaviour. Again,

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[209] *Tardif Affidavit*, Exhibit “P”, “OEB Market Surveillance Panel report dated February 2018”, p 11, p A1938.

[210] *Tardif Affidavit*, Exhibit “P”, “OEB Market Surveillance Panel report dated February 2018”, p 13, p A1940.

[211] *Doolittle Affidavit*, Exhibit “U”, “IESO Preparing for the Launch of the Renewed Market - Intertie Traders and Transmission Rights Auction Participants presentation dated April 10, 2025”, p 9, p A1525.

no such egregious market manipulation or nefarious conduct has been alleged against Nexus Energy in this case.

154. In any event, the IESO's Market Renewal Project in May 2025 and related IESO statements above are a startingly clear admission against interest in this Arbitration. In effect, the IESO has admitted there were gaps in the Market Rules for collecting "avoided congestion rents" and have finally revised the methodology from May 2025 onwards – and finally with published notice to market participants so they can govern themselves accordingly.

Estoppel by representation on the basis of silence or inaction by the IESO/MACD

155. Further and in the alternative, if MACD genuinely believed that it had the authority to seek payment for "avoided congestion rents" under Chapter 3, section 6.6.10A.2 of the Market Rules then, at a minimum, it behooved the IESO as a public sector regulator to make known such a change in approach to affected market participants.[212] This is especially so given the extensive stakeholder engagement and MACD Report on the issue of failed intertie transactions in 2005 and the resulting Market Rule Amendments in 2006.[213]

156. For context, this is a heavily regulated industry built on frequent and extensive publication by the IESO and MACD. MACD publishes express guidance on its Market Rule interpretations ("**Interpretation Bulletins**") and their potential application to

[212] *Abbott* at para 73.
[213] *Doolittle Affidavit*, Exhibit "I", "IESO report entitled 'Intertie Transaction Failure Guidelines' dated November 18, 2005', pp A280-294; Exhibit "J", "IESO's 2006 Market Rule Amendment Proposals: MR-00308-R00 to MR-00308-R04", pp 169-199, pp A296-326.

compliance and other enforcement determinations ("**Statements of Approach**") on the IESO's public website.[214] One of the purposes of these publications is to "provide guidance, on a forward-looking basis, of MACD's view of the meaning of specific market rule provisions and their potential application to compliance and other enforcement determinations".[215]

157. For all of these reasons, the IESO had a duty to publish or otherwise advise market participants of new potential charges and any changes from previously published guidelines. It could not stay silent in the weeds, hoping to surreptitiously pounce with sanctions later – as it has done here against Nexus Energy.

158. At no time did MACD publish any guidance for the benefit of stakeholders on its purported ability to seek payment for "avoided congestion rents". This is despite the fact the IESO now claims to have published its sanctions for three other market participants for similarly failed intertie transactions since 2019. With respect, this IESO argument is both disingenuous and misleading:

(a) It is disingenuous because the scant details published on the IESO website about the three previous cases do not establish that they involved transactions similar to the Subject Transactions at issue in this Arbitration. The words "avoided congestion rents (ICPs)" are not even mentioned.[216] It

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[214] *Doolittle Affidavit*, Exhibit "E", "IESO 'Issued Compliance and Enforcement Guidance' webpage", pp A222-255.
[215] *Doolittle Affidavit*, Exhibit "E", "IESO 'Issued Compliance and Enforcement Guidance' webpage", pp A222-225.
[216] However, as explained above, the details of those cases, including whether they involved "avoided congestion rents (ICP)" at all, is not discernible from the brief disclosures by the IESO on its website. *Doolittle Affidavit*, p 7, paras 25-26, p A134; Exhibit "D", "IESO 'Sanctions' webpage and IESO 'Negotiated

is not credible for the IESO to claim these instances were somehow sufficient notice to Nexus Energy or other market participants – or worse yet, to constitute a precedent for the instant case.

(b) It is misleading because IESO's argument misses the point. Whatever penalties the IESO may have succeeded in extracting from other small market participants in previous confidential settlements (without evidence or public adjudication) does not determine the outcome here. This is the first dispute under the Market Rules to proceed to public arbitration, and it should be determined according to the law and evidence tendered here.

159. It is telling that despite its now fourth investigation (this time against Nexus Energy), and the first dispute to proceed to public arbitration, the IESO still did not thereafter publish or otherwise provide notice to the market of its purported authority to seek "avoided congestion rents" (other than through their inclusion in IFCs and EFCs beginning only in May 2025).

160. Instead, the IESO – *vis-a-vis* MACD – has opted to exercise its purported authority under the guise of confidential 'closed-door' investigations against single market participants like Nexus Energy without proper public disclosure. This approach is entirely inconsistent with the stated objectives of MACD including to "enable compliance by the provision of services that provide information to market participants … to foster

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Settlements' webpage'", pp A211-220; *Tardif Affidavit*, pp 4-5, paras 11-13, pp A1653-1654; *Rosati Affidavit*, pp 2-3, paras 6-7, pp A2005-2006, Exhibit "A", IESO "Sanction" webpage and IESO "Negotiated Settlements" webpage, pp A2008-2017.

compliance on a forward looking basis".[217] It is unfair to Nexus Energy and other market participants. Whether on the basis of positive representation or silence/inaction, the IESO should be estopped from its pattern of unjustly targeting market participants one by one, in confidential cash grabs unauthorized by law.

161. Furthermore, the remedy of equitable estoppel is just and reasonable in this case because:

(a) Any market inefficiencies from the applicable Subject Transactions have been fully addressed by the $1,663,000 in IFCs and EFCs already paid by Nexus Energy; and

(b) Any system reliability concerns from the applicable Subject Transactions have been fully addressed by the $1,663,000 in IFCs and EFCs already paid by Nexus Energy.

162. According to the MACD Report, there are two categories of losses or harms that are created when intertie transactions fail to flow. The first is that failed transactions can create market inefficiencies. And the second is that it can raise system reliability concerns.[218] While both are important, reliability is identified in the MACD Report as the primary goal driving MACD enforcement.[219] These are now addressed in turn.

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[217] *Doolittle Affidavit*, Exhibit "E", "IESO 'Issued Compliance and Enforcement Guidance' webpage", pp 95-98, pp A222-225.
[218] *Doolittle Affidavit*, Exhibit "I", "IESO report entitled "Intertie Transaction Failure Guidelines" dated November 18, 2005", p 4, p A283.
[219] *Doolittle Affidavit*, Exhibit "I", "IESO report entitled "Intertie Transaction Failure Guidelines" dated November 18, 2005", p 4, p A283.

Any market inefficiencies are fully addressed by IFCs and EFCs already paid

163. The MACD Report states "failed intertie transactions are a contributing factor to distorted market signals exemplified by the persistent price discrepancy between pre-dispatch and real-time prices".[220]

164. But the proposal for the Market Rule Amendments that were ultimately approved by the IESO Board of Directors in 2006 following the MACD Report, specifically stated that ""import/export failure charge[s]" … would compensate the market for intertie transaction failures that fail for reasons that are not "bona fide and legitimate"" [221] and that "[t]his settlement provision would have market participants compensate the market for deviations from their intertie transaction schedules".[222] In other words, one of the express objectives of the IFCs and EFCs is precisely to address market inefficiencies arising from failed intertie transactions.

Impacts addressed by Import Failure Charges (IFCs)

165. The IESO continues to make the same representations almost 20 years later. For example, in May 2024, the IESO publicly presented a stakeholder engagement slide deck which describes the impacts that IFCs address, as follows (bolding added)[223]:

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[220] *Doolittle Affidavit*, Exhibit "I", "IESO report entitled "Intertie Transaction Failure Guidelines" dated November 18, 2005", p 4, p A283.
[221] *Doolittle Affidavit*, Exhibit "J", "IESO's 2006 Market Rule Amendment Proposals: MR-00308-R00 to MR-00308-R04", p 2, p A297.
[222] *Doolittle Affidavit*, Exhibit "J", "IESO's 2006 Market Rule Amendment Proposals: MR-00308-R00 to MR-00308-R04", p 2, p A297.
[223] *Doolittle Affidavit*, Exhibit "S", "IESO stakeholder engagement slide deck dated May 22, 2024", p 10, p A1432.

(a) Impacts to "IESO":

(i) "system impact" – "IESO may have to constrain on generation to adjust for the unexpected deficit"; and

(ii) **"inefficient scheduling"** – "failed transaction[s] may have displaced a transaction that would have otherwise flowed"

(b) Impacts to "ratepayers":

(i) "uplifts or higher prices" – "resulting actions may increase in market costs";

(ii) **"unfunded congestion" – "unfunded congestion in the Transmission Rights (TR) clearing account";**

(c) Impacts to "trader"/market participant:

(i) "no financial penalty";

(ii) **"may have contributed to congestion but is not impacted by it as the import did not flow in [real-time]"**.

Impacts addressed by <u>Export</u> Failure Charges (EFCs)

166. Likewise, the same May 2024 public stakeholder engagement slide deck identified the following impacts that <u>E</u>FCs address (bolding added)[224]:

(a) <u>Impacts to "IESO"</u>:

(i) "system impact" – "[t]he IESO must constrain-off generation or imports to adjust for the unexpected surplus, potentially impacting baseload generation during low demand periods" (i.e. surplus baseload generation or SBG);

(ii) **"inefficient scheduling"** – "failed transaction[s] may have displaced a more economic transaction that would have otherwise flowed";

(b) <u>Impacts to "ratepayers":</u>

(i) "uplifts" – "resulting actions may increase in market costs through uplifts";

(ii) **"unfunded congestion" – "unfunded congestion in the Transmission Rights (TR) clearing account";**

(iii) "foregone energy" – "constrained-off generation is paid for by the ratepayer through global adjustment";

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[224] *Doolittle Affidavit*, Exhibit "S", "IESO stakeholder engagement slide deck dated May 22, 2024", p 11, p A1433.

(c) Impacts to "trader"/market participant:

(i) "no financial penalty" to the trader;

(ii) **"may have contributed to congestion but does not pay its share as it did not flow in [real-time]"**.

167. Again, and despite having sanctioned at least four market participants (including Nexus Energy) since 2019 allegedly for failed intertie transactions, there is zero mention in the IESO May 2024 slide deck of any purported authority or ability for MACD to seek payment for "avoided congestion rents".

168. Rather, and consistent with the MACD Report and resulting Market Rule Amendments in place since 2006, the IESO continued to publicly represent as late as May 2024 (more than one month after it issued the Notice of Alleged Breach to Nexus Energy) that market inefficiencies are addressed through the payment of IFCs and EFCs (and not "avoided congestion rents").[225]

169. Notably, as indicated in the bolded text in paragraphs 165 and 166 above, the same May 2024 presentation represented to stakeholders that "unfunded congestion" is also addressed by way of IFCs/EFCs (and not through any other or additional enforcement method such as compliance investigations).[226]

[225] *Doolittle Affidavit*, Exhibit "S", "IESO stakeholder engagement slide deck dated May 22, 2024", pp 10-11, pp A1432-1433.

[226] *Doolittle Affidavit*, Exhibit "S", "IESO stakeholder engagement slide deck dated May 22, 2024", pp 10-11, pp A1432-1433.

170. This means that only about six weeks after it issued the Notice of Alleged Breach against Nexus Energy, the IESO was still publicly representing to market participants and other stakeholders that "unfunded congestion" is addressed through IFCs and EFCs.[227] This is more than a month after the April 12, 2024 meeting during which Nexus Energy challenged the IESO's authority to pursue compliance action for "avoided congestion rents" (other than through IFCs and EFCs and absent egregious behaviour)![228]

171. As stated, Nexus Energy already has paid to the IESO over $1,663,000 in IFCs and EFCs for failed intertie transactions between December 2017 and December 2023 (and which payments are not being challenged in this Arbitration).[229] Any market inefficiencies caused by the applicable Subject Transactions have been addressed.

Any system reliability concerns are addressed through IFCs and EFCs already paid

172. The second and far more significant potential harm are adverse impacts to grid system reliability.[230] However, as described in the reproduced portions of the IESO May 2024 slide deck in paragraphs 165 and 166 above, this type of "system impact" is already addressed by the over $1,663,000 in IFCs and EFCs that Nexus Energy has paid including for the applicable Subject Transactions.

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[227] *Doolittle Affidavit*, Exhibit "S", "IESO stakeholder engagement slide deck dated May 22, 2024", pp 10-11, pp A1432-1433.

[228] *Tardif Affidavit*, p 7, para 20, p A1656.

[229] *Doolittle Affidavit*, p 8, para 31, p A135.

[230] *Doolittle Affidavit*, Exhibit "I", "IESO report entitled "Intertie Transaction Failure Guidelines" dated November 18, 2005", p 4, p A283.

173. Moreover, the MACD Report states that "[i]n general the reliability impacts of transaction failures fall into 3 categories".[231] The first category is that if import transactions are scheduled in pre-dispatch to serve real-time demand in Ontario, and those import transactions fail to flow, then the IESO could suffer an electricity supply shortfall and/or result in it having to dispatch higher-priced supply at the last minute.[232]

174. However, only about 100 (i.e. about 6%) of the 1,658 Subject Transactions, were import transactions into Ontario.[233] The remaining 94% or so of the Subject Transactions were export transactions directed out from Ontario.

175. The MACD Report says that, in addition to failed import transactions, failed export transactions can also cause reliability concerns in that they can create excess generation/ supply (surplus baseload generation or SBG) above an acceptable level that the system can accommodate.[234] However, Nexus Energy's analysis shows that the IESO was experiencing potential or actual SBG conditions during only approximately 246 of the 1,658 Subject Transactions, i.e. less than 15% of the time.[235]

176. The second category of potential system reliability impacts arising from failed export transactions, according to the MACD Report, is that failed transactions can create

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[231] *Doolittle Affidavit*, Exhibit "I", "IESO report entitled "Intertie Transaction Failure Guidelines" dated November 18, 2005", p 4, p A283.
[232] *Doolittle Affidavit*, Exhibit "I", "IESO report entitled "Intertie Transaction Failure Guidelines" dated November 18, 2005", p 5, p A284.
[233] *Tardif Affidavit*, p 9, para 27, p A1658; see also Exhibit "C", "Surplus baseload generation (SBG) data analysis", pp A1672-1674.
[234] *Doolittle Affidavit*, Exhibit "I", "IESO report entitled "Intertie Transaction Failure Guidelines" dated November 18, 2005", p 5, p A284.
[235] *Tardif Affidavit*, p 9, para 28, p A1658; see also Exhibit "C", "Surplus baseload generation (SBG) data analysis", pp A1672-1674.

"Operating Security Limits" impacts which in turn can cause the "net intertie schedule limit" to be exceeded.[236] However, nowhere in the Notice of Alleged Breach nor the Notice of Non-Compliance does it contain information pertaining to if and to what extent the Subject Transactions caused the net intertie schedule limit to be exceeded.[237]

177. In an attempt to conduct this analysis itself, Nexus Energy asked MACD on May 6, 2024 to provide data indicating during which of the Subject Transactions Nexus Energy was the marginal bidder.[238] However, MACD refused to satisfy Nexus Energy's information request because it was too onerous for MACD to do so.[239]

178. The third potential adverse impact of failed transactions, according to the MACD Report, is purportedly unfunded congestion in the IESO Transmission Rights Clearing Account ("**TRCA**").[240] But ICP is collected only on *actual* flows.[241]

179. The TRCA is designed by the IESO to offset transmission rights payouts to transmission rights holders, with any surplus being disbursed to market participants.[242] It is not a reimbursement of monies paid by ratepayers, to ratepayers. While the TRCA has

[236] *Doolittle Affidavit*, Exhibit "I", "IESO report entitled "Intertie Transaction Failure Guidelines" dated November 18, 2005", p 5, p A284.
[237] *Doolittle Affidavit*, Exhibit "C", "Notice of Alleged Breach dated April 4, 2024", pp A164-209; and Exhibit "F", "Notice of Non-Compliance dated December 17, 2024", pp A227-250.
[238] *Tardif Affidavit*, Exhibit "B", "Email exchange between MACD and Nexus Energy dated May 6-9, 2024," pp A1668-1670.
[239] *Tardif Affdavit*, pp 7-8, paras 22-23, pp A1656-1657.
[240] *Doolittle Affidavit*, Exhibit "I", "IESO report entitled "Intertie Transaction Failure Guidelines" dated November 18, 2005", p 5, p A284.
[241] *Doolittle Affidavit*, p 9, para 34, p A136.
[242] *Doolittle Affidavit*, p 9, para 34, p A136.

had shortfalls in the past, no shortfall appears to have occurred during the Subject Transactions, i.e. between December 2017 and December 2023.[243]

180. Accordingly, even if the IESO is found to have authority to collect "congestion rents (ICP) avoided" and to have fulfilled its duty of fairness (both of which are denied), there are several reasons why the IESO should be estopped from enforcing the IESO Order in these circumstances. Preventing enforcement on these facts would be just and reasonable, relief that is well within the arbitrator's powers under Chapter 3, section 2.7.25 of the Market Rules.[244]

PART IV - CONCLUSIONS

181. The Notice of Non-Compliance and IESO Order are unlawful and should not be enforced on three independent grounds: no authority under the Market Rules; breach of the duty of fairness; and estoppel.

182. **No Authority:** The IESO Order seeks adjustment for "congestion rents (ICPs) avoided" despite the absence of any authority under the Market Rules to do so. Indeed, the phrase "avoided congestion rents" does not even appear in the IESO's Market Rules or Market Manuals.

183. Chapter 3, section 6.6.10A provides the IESO with the authority to "adjust settlement amounts".[245] But for several different reasons, "congestion rents" are not a

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[243] *Doolittle Affidavit*, p 9, para 35, p A136 and Exhibit "H", "IESO Transmission Rights Clearing Account Disbursement webpages", pp A255-278.

[244] *Doolittle Affidavit*, Exhibit "L", "Chapter 3 of the IESO Market Rules issued May 1, 2023", pp 21-22, ss 2.7.25, pp A394-395; and see p 1, s 2.1.1 and s 2.1.2, p A374.

[245] *Doolittle Affidavit*, Exhibit "L", "Chapter 3 of the IESO Market Rules issued May 1, 2023", p 77, s 6.6.10A, p A450.

"settlement amount" as defined under Chapter 11 of the Market Rules[246], or otherwise. Hence it should come as no surprise that "congestion rents" have no associated IESO charge code, equation or settlement amount acronym.[247] Therefore, the IESO was acting without authority and in breach of its contract with Nexus Energy.

184. **Duty of Fairness Breaches:** As a public sector entity, the IESO's decisions (including the IESO Order) must be made in accordance with its duty of fairness. In this case, the IESO (including MACD) repeatedly failed to meet this duty.

185. The IESO Order was issued under the responsibility of Bob Yeoman, and in turn the supervision of Glenn McDonald, in a way that fails to observe the mandatory division of the MAU from the rest of MACD contrary to the OEB Act, OEB By-Law #2 and the Protocol between the IESO and the OEB. This creates a fundamental lack of transparency and an actual or a reasonable apprehension of impartiality or bias.

186. MACD's underlying investigation, including the issuance of the Notice of Alleged Breach and the Notice of Non-Compliance, also failed to observe Nexus Energy's participatory rights and deprived Nexus Energy of its right to a fair and open administrative decision-making process.

187. MACD prematurely assessed the financial sanction against Nexus Energy. MACD is not permitted under Chapter 3, sections 6.2.4 and 6.2.5 of the Market Rules to make

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[246] *Doolittle Affidavit*, Exhibit "O", "Chapter 11 of the IESO Market Rules issued November 29, 2023", p 38, p A827.

[247] *Doolittle Affidavit*, Exhibit "R", "IESO Market Manual entitled "IESO Charge Types and Equations" dated November 29, 2023", pp A1094-1421.

breach determinations, let alone assess sanctions, without first giving Nexus Energy an opportunity to provide a substantive response to the Notice of Alleged Breach.[248]

188. MACD also failed to provide to Nexus Energy much of the evidence listed in paragraph 13 of the Notice of Alleged Breach.[249] When Nexus Energy requested further relevant information and evidence, MACD refused much of it on the basis that it would be too burdensome for MACD.[250] This severely limited Nexus Energy's ability to make responding representations for the IESO's consideration as provided for under Chapter 3, sections 6.2.4 and 6.2.5 of the Market Rules.[251]

189. Nexus Energy had a legitimate expectation that MACD would conduct its investigation and exercise its enforcement authority in accordance with the procedural protections afforded to market participants under the governing legislative, regulatory and contractual requirements including the Market Rules and Market Manuals. In a variety of ways, this was not done.

190. **Estoppel:** Even if it determined that the IESO had the authority and did not breach its duty of fairness (both of which are denied), the IESO should be estopped from enforcing the Notice of Non-Compliance and IESO Order.

191. Beginning over 20 years ago in 2005, MACD expressly represented that it would be moving away from a compliance investigation regime with respect to failed intertie

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[248] *Doolittle Affidavit*, Exhibit "L", "Chapter 3 of the IESO Market Rules issued May 1, 2023", p 59, ss 6.2.4 and ss 6.2.5, p A432.

[249] *Tardif Affidavit*, pp 2-3, para 4, pp A1651-1652.

[250] *Tardif Affidavit*, p 8, para 23, p A1653.

[251] *Doolittle Affidavit*, Exhibit "L", "Chapter 3 of the IESO Market Rules issued May 1, 2023", p 59, ss 6.2.4 and 6.2.5, p A432.

transactions except in instances of egregious behaviour.[252] Instead, the IESO adopted a market-based approach where failed intertie transactions would become subject to automated settlement charges in the form of IFCs/EFCs.[253]

192. These published representations were made in the MACD Report and surrounding the resulting Market Rule Amendments that became effective in June 2006. Nexus Energy relied on these public representations when it registered to participate in the IESO-administered markets in 2017 and structured its trading activities accordingly.[254]

193. If the IESO was of the view that, in addition to IFCs and EFCs, it had the authority to seek payment of "avoided congestion rents", then the IESO had a duty[255] to make that expressly clear to affected market participants including Nexus Energy.

194. To the extent the IESO relies on its published summaries of other market participants beginning in 2019 for failed intertie transactions, the summaries fail to mention any sanctions for "avoided congestion rents" or ICP.[256] Likewise, the IESO's 2018 response to the MSP's 2017 report simply does not suffice.

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[252] *Doolittle Affidavit*, Exhibit "I", "IESO report entitled 'Intertie Transaction Failure Guidelines' dated November 18, 2005", p 10, p A289
[253] *Doolittle Affidavit*, Exhibit "I", "IESO report entitled 'Intertie Transaction Failure Guidelines' dated November 18, 2005", pp 10-11, pp A289-290.
[254] *Tardif Affidavit*, pp 6-7, para 17-19, pp A1655-1656.
[255] *Abbott*, para 73.
[256] *Doolittle Affidavit*, Exhibit "D", "IESO 'Sanctions' webpage and IESO 'Negotiated Settlements webpage", pp A211-220.

195. Like it did in 2005-2006, the IESO should be expected to, at a minimum, publish specific information on such a change in its compliance and enforcement approach toward failed intertie transactions.

196. Instead, and incredibly even after its investigation of Nexus Energy and issuance of the Notice of Alleged Breach in April 2024, the IESO continued to publicly represent until at least May 2024 that IFCs and EFCs were the mechanism by which failed intertie transactions would be addressed from a compliance perspective.[257] The IESO made no public mention of "avoided congestion rents" until they became expressly included as part of the calculation of IFCs/EFCs from May 2025 onwards.[258]

197. Hence, either by way of positive representation or silence/inaction, the IESO should be estopped from enforcing the Notice of Non-Compliance and IESO Order against Nexus Energy in this case.

PART V - RELIEF REQUESTED

198. For these reasons, Nexus Energy requests that an arbitral award be issued under Chapter 3, section 2.7.25 of the Market Rules to the following effect[259]:

(a) Finding that in its compliance investigation against Nexus Energy (bearing compliance case number COM237240), the IESO (including MACD) misinterpreted and misapplied Chapter 3, section 6.6.10A;

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[257] *Doolittle Affidavit*, Exhibit "S", "IESO stakeholder engagement slide deck dated May 22, 2024", pp A1423-1439.

[258] *Doolittle Affidavit*, Exhibit "U", "IESO Preparing for the Launch of the Renewed Market - Intertie Traders and Transmission Rights Auction Participants presentation dated April 10, 2025", p 9, p A1525.

[259] *Doolittle Affidavit*, Exhibit "L", "Chapter 3 of the IESO Market Rules issued May 1, 2023", pp 21-22, ss 2.7.25, pp A394-395.

(b) Directing the IESO (including MACD) to interpret and apply Chapter 3, section 6.6.10A such that "avoided congestion rents" are not recoverable from Nexus Energy;

(c) In the alternative to (a) and (b) above, prohibiting the IESO (including MACD) from enforcing the Notice of Non-Compliance and IESO Order against Nexus Energy on the basis that in these circumstances such prohibition would be just and reasonable;

(d) Prohibiting the IESO (including MACD) from considering the Subject Transactions for the purpose of alleging and/or determining any future Market Rules breaches and from assessing future sanctions against Nexus Energy; and

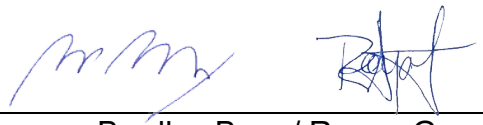
(e) Directing the IESO to repay to Nexus Energy the sum of $2,078,824.92 within 30 days, plus prejudgment interest to be calculated in accordance with the *Courts of Justice Act* (Ontario) with necessary modifications.

199. Further and in any event of the outcome, given the circumstances of this case and the IESO's conduct, Nexus Energy respectfully requests an award of its costs including the costs of this Arbitration pursuant to Chapter 3, section 2.7.32.[260]

ALL OF WHICH IS RESPECTFULLY SUBMITTED this 31st day of October, 2025.

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[260] *Doolittle Affidavit*, Exhibit "L", "Chapter 3 of the IESO Market Rules issued May 1, 2023", pp 25, ss 2.7.32, p A398.



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LIST OF AUTHORITIES

1. *1797472 Ontario Inc v Independent Electricity System Operator*, 2024 ONSC 2130
2. *Abbott v. Canada (T.D.)*, 2001 FCT 242
3. *Agraira v Canada (Public Safety and Emergency Preparedness)*, 2013 SCC 36
4. *Baker v Canada (Minister of Citizenship and Immigration)*, 1999 CanLII 699 (SCC)
5. Huscroft, Grant, "From Natural Justice to Fairness: Thresholds, Content, p And the Role of Judicial Review" in C.M Flood and L Sossin, eds., A*dministrative Law in Context*, 2nd ed (Toronto: Emond Montgomery, 2012), Chapter 5
6. *Ledcor Construction Ltd v Northbridge Indemnity Insurance Co*, 2016 SCC 37
7. *Sattva Capital Corp v Creston Moly Corp*, 2014 SCC 53
8. *Ryan v Moore*, 2005 SCC 38

I certify that I am satisfied as to the authenticity of every authority.

Note: Under the Rules of Civil Procedure, an authority or other document or record that is published on a government website or otherwise by a government printer, in a scholarly journal or by a commercial publisher of research on the subject of the report is presumed to be authentic, absent evidence to the contrary (rule 4.06.1(2.2)).

Date October 31, 2025

Bradley Berg / Reena Goyal

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SECOND EDITION

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CHAPTER FIVE

From Natural Justice to Fairness: Thresholds, Content, and the Role of Judicial Review

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I. Introduction

People are affected by a wide variety of decisions made on a daily basis by public authorities—from Cabinet ministers to bureaucrats, tribunals, agencies, boards, commissions, and other public authorities. The one thing these decisions have in common is that, in general, they must be made pursuant to a fair procedure.

The development of a "duty of fairness" is one of the great achievements of modern administrative law. It promotes a better-informed decision-making process, leading to better public policy outcomes, and helps to ensure that individuals are treated with respect in the administrative process. As we will see, the duty is context-specific: its content is articulated having regard to the circumstances surrounding the relevant decision and can be tailored to suit the wide variety of decision-making contexts to which it applies.

This chapter traces the development of the duty, considers the threshold for its application, and fleshes out the contents of the duty. The most common means to attack an adverse administrative decision is to impugn the procedure pursuant to which the decision was made, and the chapter concludes with a consideration of judicial oversight of the duty and the consequences of an unfair procedure. Some practical implications flowing from the duty are discussed by Freya Kristjanson and Leslie McIntosh in Chapter 6, Advocacy Before Administrative Tribunals.

II. From Natural Justice to Fairness

The availability of procedural protection in administrative law once depended on the way in which a decision was characterized. "Judicial" and "quasi-judicial" decisions were required to be made in accordance with the rules of natural justice: *audi alteram partem*, which requires a decision-maker to "hear the other side" in a dispute before deciding, and *nemo judex in sua causa*, which precludes a man from being a "judge in his own cause."[1]

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1 See, generally, William Wade & Christopher Forsyth, *Administrative Law*, 10th ed. (Oxford: Oxford University Press, 2009), chapters 13-14.

So-called administrative decisions—virtually any decision other than a judicial or quasi-judicial decision—could be made without any procedural impediments. The dichotomy between judicial and administrative decisions made administrative law "formalistic"[2] in nature, and judicial review proceedings focused on the nature of the power exercised rather than the impact of its exercise. To obtain procedural protection, an applicant had to convince a court that a particular decision could properly be characterized as judicial or quasi-judicial. A successful applicant would receive the full range of natural justice protection. An unsuccessful applicant would receive no procedural protection at all.

The growth of the modern regulatory state—and with it the number of important administrative decisions made by everyone from bureaucrats to administrative tribunals and ministers of the Crown—made change inevitable. It was indefensible that important decisions could be made without any procedural protection being afforded simply because they were classified as administrative in nature. Following the lead of the House of Lords in *Ridge v. Baldwin*,[3] the Supreme Court of Canada abandoned the all-or-nothing approach to the provision of procedural protection in *Nicholson v. Haldimand-Norfolk (Regional) Police Commissioners*.[4] *Nicholson* concerned the summary dismissal of a probationary police constable some 15 months into his term of service. He was not given a reason for his dismissal, nor was he given notice or allowed to make any representations prior to his dismissal. Regulations made under provincial legislation provided that police officers could not be penalized without a hearing and right of appeal, but added that the Board of Commissioners of Police had authority "to dispense with the services of any constable within eighteen months of his becoming a constable."[5]

Under the traditional common-law approach that would have been the end of the matter; Nicholson was not entitled to a hearing before his dismissal, nor could his dismissal be characterized as the sort of "judicial or quasi-judicial" decision to which natural justice protection applied. It was an administrative matter and, as such, Nicholson would not have been entitled to any protection at all. In these circumstances, a 5:4 majority of the Supreme Court held that a general duty of "procedural fairness" applies to administrative decisions. Writing for a majority of the Court, Chief Justice Laskin justified the new duty as follows:

> [T]he classification of statutory functions as judicial, quasi-judicial or administrative is often very difficult, to say the least; and to endow some with procedural protection while denying others any at all would work injustice when the results of statutory decisions raise the same serious consequences for those adversely affected, regardless of the classification of the function in question.[6]

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2 Frederick Schauer discusses some of the vices, and virtues, of formalism in *Thinking Like a Lawyer: A New Introduction to Legal Reasoning* (Cambridge, MA: Harvard University Press, 2009) at 29-35.

3 [1964] A.C. 40 (H.L.) (dismissal of chief constable of Borough of Brighton without notice or right to be heard at meeting of watch committee).

4 [1979] 1 S.C.R. 311 [*Nicholson*].

5 *Ibid.* at para. 5, citing the *Police Act*, R.S.O. 1970, c. 351, Reg. 680, s. 27(b).

6 *Ibid.* at para. 23.

On this approach, the ability of the board to dismiss Nicholson for any reason (or none at all) was irrelevant. Plainly, Nicholson could not claim the procedural protection the regulations afforded to those with 18 months of service (that is, an oral hearing with a right of appeal) but, according to Laskin C.J., it did not follow that he must be denied any protection at all. Nicholson was entitled to be treated fairly, not arbitrarily; he was entitled to be told why he was being dismissed and given an opportunity to make submissions—orally or in writing, at the board's discretion—before he was dismissed.

Laskin C.J. did not reject the distinction between administrative and judicial or quasi-judicial decisions in *Nicholson*. Instead, he accepted as a common-law principle the notion that "in the sphere of the so-called quasi-judicial the rules of natural justice run, and that in the administrative or executive field there is a general duty of fairness."[7] However, in subsequent cases the "duty of fairness" came to replace natural justice as the organizing principle in administrative law and, as a result, there is no longer any reason to differentiate between the two concepts or the spheres in which they operate.[8] The duty of fairness applies across the spectrum of decisions that public authorities may make and the requirements of the duty vary in accordance with the relevant circumstances.

"Fairness" has become short form for procedural fairness, but it is important not to lose sight of the essentially procedural character of the duty. The duty of fairness is concerned with ensuring that public authorities act fairly in the course of *making* decisions, not with the fairness of the actual decisions they *make*. The duty of fairness has nothing to say about the outcome of particular decisions, and in particular does not require that the decisions of public authorities be considered "fair"—a subjective and contestable concept that Canadian administrative law eschews.[9]

The duty of fairness promotes sound public administration and the accountability of public decision-makers by ensuring that decisions are made with input from those affected by them; well-informed decisions are likely to be better decisions, and decisions made pursuant to transparent, participatory processes promote important rule-of-law values. Fairness is,

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7 *Ibid.* at para. 22, citing *Bates v. Lord Hailsham*, [1972] 1 W.L.R. 1373 at 1378 (Ch. D.).

8 This is not a uniquely Canadian development. In *Kioa v. West* (1985), 159 C.L.R. 550, Mason J. summed up English and Australian law as follows:

> It has been said on many occasions that natural justice and fairness are to be equated .... And it has been recognized that in the context of administrative decision-making it is more appropriate to speak of a duty to act fairly or to accord procedural fairness. This is because the expression "natural justice" has been associated, perhaps too closely associated, with procedures followed by courts of law (at para. 30).

Nevertheless, the language of natural justice survives in most jurisdictions and is often used interchangeably with fairness terminology. In New Zealand, for example, the *New Zealand Bill of Rights Act 1990* includes a right to natural justice (s. 27), but the right is understood as a codification of the duty of fairness. See P. Rishworth, G. Huscroft, R. Mahoney, & S. Optican, *The New Zealand Bill of Rights* (Melbourne: Oxford University Press, 2003), chapter 27.

9 Under the approach set out by the Supreme Court of Canada in *Dunsmuir v. New Brunswick*, 2008 SCC 9, [2008] 1 S.C.R. 190 [*Dunsmuir*], substantive decisions may be reviewed for legal correctness in some cases or reasonableness in others. Even in this context, however, judicial review is not concerned with the substantive "fairness" of a decision.

in this sense, a means to an end. But the importance of the duty transcends its instrumental purpose. The duty of fairness is important in its own right, for it ensures that people are allowed to participate meaningfully in decision-making processes that affect them. In other words, the duty protects dignitary interests by requiring that people be treated with respect. As we will see, both rationales support the Court's strict remedial approach in cases where the duty is breached: procedurally unfair decisions are quashed and remitted to be made in accordance with the required procedural protection.[10]

In general, the duty of fairness requires two things, both of which are modern restatements of venerable natural justice protections: (1) the right to be heard, and (2) the right to an independent and impartial hearing.[11] Fairness is a common-law concept and, subject only to compliance with the *Canadian Charter of Rights and Freedoms* (the Charter), may be limited or even ousted by ordinary legislation. Such is its importance, however, that courts will require specific legislative direction before concluding that this has occurred. In *Kane v. Bd. of Governors of U.B.C.*, Justice Dickson put the point this way: "To abrogate the rules of natural justice, express language or necessary implication must be found in the statutory instrument."[12] This is justified on the basis that courts presume that the legislature intended procedural protection to apply, even if nothing is said. As Justice Byles stated in *Cooper v. Board of Works for Wandsworth District*, "[A]lthough there are no positive words in a statute requiring that the party shall be heard, yet the justice of the common law will supply the omission of the legislature."[13] On this approach, the courts acknowledge the supremacy of the legislature and at the same time confer heightened, quasi-constitutional protection upon the common-law duty of fairness.[14]

The duty of fairness is codified to varying degrees in Canadian legislation. At the federal level, the *Canadian Bill of Rights* protects a "right to a fair hearing in accordance with the

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10 *Cardinal v. Director of Kent Institution*, [1985] 2 S.C.R. 643 at para. 23 [*Cardinal*], discussed in the text below.

11 The right to an independent and impartial hearing is discussed by Laverne Jacobs in Chapter 8, Caught Between Judicial Paradigms and the Administrative State's Pastiche: "Tribunal" Independence, Impartiality, and Bias.

12 [1980] 1 S.C.R. 1105 at 1113. For its part, the High Court of Australia has rendered it difficult, if not virtually impossible, for legislation to limit or oust procedural protection, outlining a presumption that it is "highly improbable that Parliament would overthrow fundamental principles or depart from the general system of law, without expressing its intention with *irresistible clearness*." See *Saeed v. Minister for Immigration and Citizenship*, [2010] H.C.A. 23 (23 June 2010) at para. 15 (emphasis added).

13 (1863), 14 C.B. (N.S.) 180 at 194. In *Daganayasi v. Minister of Immigration*, [1980] 2 N.Z.L.R. 130 at 141, Cooke J. (as he then was) stated that the availability of fairness protection depends "either on what is to be inferred or presumed in interpreting the particular Act ... or on judicial supplementation of the Act when this is necessary to achieve justice without frustrating the apparent purpose of the legislation" (internal citations omitted).

14 This point was put strongly by the High Court of Australia in *Electrolux Home Products Pty. Ltd. v. Australian Workers' Union* (2004), 221 C.L.R. 309 at 329: "The presumption is not merely a common sense guide to what a Parliament in a liberal democracy is likely to have intended; it is a working hypothesis, the existence of which is known both to Parliament and the courts, upon which statutory language will be interpreted. The hypothesis is an aspect of the rule of law."

principles of fundamental justice for the determination of his rights and obligations."[15] Procedural protection has been codified more specifically in provincial legislation in Alberta,[16] British Columbia,[17] Ontario,[18] and Quebec.[19] In addition, it is important to note that federal and provincial legislation may establish procedural requirements, short of a complete code, that apply in particular contexts. It is not unusual for legislation or regulations to particularize, for example, notice requirements and rights to make submissions for particular tribunals. The common-law duty of fairness supplements existing statutory duties and fills the gap where none exist. Section 7 of the Charter provides a constitutional backstop for procedural protection, but, as we will see, this right applies in a narrower range of circumstances than the duty of fairness.[20]

Given the wide range of decisions to which the duty of fairness applies, the protection afforded by the duty is necessarily flexible rather than fixed. Although the language of the duty of fairness speaks of the right to a "hearing," this does not mean that formal, oral hearings are required. Oral hearings will sometimes be required by the duty of fairness, but they are not the norm. The modern state could not function if an oral hearing were required every time an administrative decision of some sort were made—a problem not only for the state but also for those who benefit from, or are subject to, the burden of administrative decisions. In practice, the content of the duty is informed by the context in which a particular decision is made and varies in accordance with a number of factors. In other words, the duty may be satisfied by different protection in different decision-making contexts. Thus, to say that the duty of fairness applies to a particular decision-making process is to say little. Everything depends on what the duty is understood as requiring in the circumstances, and this has a normative dimension: fairness requires the procedural protection the courts think *ought* to be required before a decision is made in particular circumstances. An oral hearing

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15 S.C. 1960, c. 44, s. 2(e). In *Duke v. The Queen*, [1972] S.C.R. 917 at 923, Justice Fauteux discussed this provision as follows: "Without attempting to formulate any final definition of those words, I would take them to mean, generally, that the tribunal which adjudicates upon his rights must act fairly, in good faith, without bias, and in a judicial temper, and must give to him the opportunity adequately to state his case." In *Re B.C. Motor Vehicle Act*, [1985] 2 S.C.R. 486 at para. 58 [*Re B.C. Motor Vehicle Act*], Justice Lamer noted that the principles of fundamental justice in the *Bill of Rights* were contextually limited to procedural matters because of their qualification of the right to a fair hearing. He proffered a more expansive definition of fundamental justice in s. 7 of the *Canadian Charter of Rights and Freedoms*, among other things because s. 7 is set out in the context of deprivations of life, liberty, and security of the person, which he considered more fundamental rights. Evan Fox-Decent and Alexander Pless discuss the relevance of Charter protection in greater depth in Chapter 12, The Charter and Administrative Law: Cross-Fertilization or Inconstancy?

16 *Administrative Procedures and Jurisdiction Act*, R.S.A. 2000, c. A-3.

17 *Administrative Tribunals Act*, S.B.C. 2004, c. 45.

18 *Statutory Powers Procedure Act*, R.S.O. 1990, c. S.22.

19 Quebec has codified procedures in several statutes. The *Civil Code of Quebec*, R.S.Q., c. C-1991; the *Charter of Human Rights and Freedoms*, R.S.Q., c. C-12; *Administrative Justice Act*, R.S.Q., c. J-3; and the *Code of Civil Procedure*, R.S.Q., c. C-25 are discussed in Denis Lemieux, "The Codification of Administrative Law in Quebec" in Grant Huscroft & Michael Taggart, eds., *Inside and Outside Canadian Administrative Law* (Toronto: University of Toronto Press, 2006).

20 The impact of the Charter on administrative law is discussed by Evan Fox-Decent and Alexander Pless in Chapter 12, The Charter and Administrative Law: Cross-Fertilization or Inconstancy?

might be required in some cases, involving processes similar to those used in the judicial system. In other contexts, however, the requirement to provide a hearing may be satisfied by as little as an exchange of written correspondence prior to a decision being made.

Two questions arise when judicial review proceedings are brought alleging a breach of the duty of fairness. First, has the threshold for the application of the duty been met? Second, what does the duty of fairness require in the relevant circumstances? It is important to emphasize that courts require decisions about threshold and content of the duty of fairness to be made correctly. If they are not, the substantive decision made in a particular matter will be quashed and remitted to be remade in accordance with the appropriate procedures.

An order quashing a decision for a breach of the duty of fairness does not, in theory, affect the substantive decision that might be made subsequently; it means only that the decision must be remade in accordance with the appropriate procedures. In practice, however, it may be difficult for a decision-maker to reach the same substantive decision on a rehearing. Fair procedures may make it easier to argue in support of particular substantive outcomes on a rehearing; moreover, there may be impediments—practical or political—to reaching the same decision on a rehearing. Thus, success on an application for judicial review on fairness grounds may have the indirect effect of helping an applicant to secure a preferred substantive outcome. At the very least, it will give the applicant another chance to obtain that outcome, and ensures that the substantive decision will be made on a well-informed basis in any event. Even if the same substantive decision is reached following a rehearing, it will have a greater claim to legitimacy.

III. The Threshold Test: When is Fairness Required?

A. Rights, Privileges, and Interests

Subject to some exceptions, discussed below, it is well established that the duty of fairness applies to the decisions of public authorities—for example, executive actors, tribunals, and officials acting pursuant to statutory authority—that affect an individual's *rights*, *privileges*, or *interests*.[21] There is little dispute about the meaning of these terms because they are not meant to limit the availability of fairness protection. On the contrary, their purpose is to expand the range of decisions subject to the fairness duty beyond the narrower range of decisions traditionally required to be made in accordance with natural justice protection.

Taken as a whole, the concepts of rights, privileges, and interests are sufficiently broad in scope to cover most decisions made by public authorities that affect or have the potential to affect an individual in important ways, even in the absence of any sort of substantive entitlement. So, for example, although prison inmates may have no right to early release, once the

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21 Justice Le Dain summed up the Court's case law in this way in *Cardinal, supra* note 10 at para. 14:

> [T]here is, as a general common law principle, a duty of procedural fairness lying on every public authority making an administrative decision which is not of a legislative nature and which affects the rights, privileges or interests of an individual.
>
> Thus, we will not be concerned with procedural entitlements that may arise in a variety of private contexts—for example, decisions made by private clubs that may affect the rights of their members. In these contexts, entitlements are likely to arise out of contractual terms, express or implied, rather than public law.

state establishes a parole system of some sort, they are entitled to procedural fairness in its operation.

B. Constitutional Protection[22]

When, and to what extent, does the Charter require the provision of procedural protection?[23] Section 7 of the Charter provides as follows:

> Everyone has the right to life, liberty and security of the person and the right not to be deprived thereof except in accordance with the principles of fundamental justice.

Despite the conjunctive nature of its language, it is well established that s. 7 protects a single right: the right not to be deprived of life, liberty, or security of the person except in accordance with the principles of fundamental justice. The Supreme Court of Canada has held that the principles of fundamental justice subsume procedural fairness protection,[24] but the right does not constitutionalize the duty of fairness per se. Section 7 applies only in the context of deprivations of life, liberty, and security of the person, and this establishes a higher threshold than simply demonstrating that a right, privilege, or interest is affected.

For example, an application to renew a taxi licence may give rise to an entitlement to fairness protection at common law, but it does not give rise to Charter protection because the denial of a licence does not constitute a deprivation of life, liberty, or security of the person. Licensing is, in this context, an economic matter, and the Court has not interpreted s. 7 of the Charter as including economic rights.[25] Thus, ordinary legislation could limit or even oust the application of the duty of fairness to the licensing scheme without infringing the Charter.

In the event that a deprivation of life, liberty, or security of the person is found not to be in accordance with the principles of fundamental justice, it is highly unlikely that it will be considered justified under s. 1 of the Charter. The Court has held that infringement of s. 7 may be considered justified only in "extraordinary circumstances where concerns are grave and the challenges complex."[26]

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22 The development of duty to consult in the context of Aboriginal rights and its link to the duty of fairness is discussed in David Mullan, "The Supreme Court and the Duty to Consult Aboriginal Peoples: A Lifting of the Fog?" (2012) C.J.A.L.P. 233 at 241-45. See also the discussion by Janna Promislow and Lorne Sossin in Chapter 13, In Search of Aboriginal Administrative Law.

23 The impact of the Charter on administrative law is discussed by Evan Fox-Decent and Alexander Pless in Chapter 12, The Charter and Administrative Law: Cross-Fertilization or Inconstancy?

24 *Re B.C. Motor Vehicle Act*, *supra* note 15. More controversially, the Court held that the principles of fundamental justice include a substantive component, despite the apparent intention of the framers to limit the right to matters of procedure. See Peter Hogg, *Constitutional Law of Canada*, looseleaf (Scarborough, ON: Carswell, 1997) at para. 44.10(a).

25 *Gosselin v. Quebec (Attorney General)*, [2002] 4 S.C.R. 429 at paras. 80-82. However, the Court left open the possibility that s. 7 might be interpreted to include positive obligations in future cases. See the discussion in Grant Huscroft, "A Constitutional 'Work in Progress'? The Charter and the Limits of Progressive Interpretation" in Grant Huscroft & Ian Brodie, eds., *Constitutionalism in the Charter Era* (Toronto: LexisNexis, 2004).

26 See *Charkaoui v. Canada (Citizenship and Immigration)*, [2007] 1 S.C.R. 350 at para. 66, citing *Re B.C. Motor Vehicle Act*, *supra* note 15 at para. 85, per Lamer J. (listing "exceptional conditions such as natural disasters, the outbreak of war, epidemics, and the like").

IV. Limitations on the Application of the Duty of Fairness

Although the duty of fairness applies to a broad range of decision-making contexts, there are limitations on the reach of the duty, both inherent in the concept and imposed on the concept by the courts. Significant limitations on the duty are discussed below.

A. The Duty Applies to Decisions

The duty of fairness governs decision-making processes, which is another way of saying that the duty applies only in contexts in which *decisions* may be made. In principle, it does not apply to investigations or advisory processes that may occur prior to the commencement of a formal decision-making process.[27] This is so because the imposition of fairness duties at a preliminary stage may well compromise the relevant processes. To take an obvious example, it would be absurd to require officials charged with responsibility for investigating breaches of the law to provide notice before commencing their investigations. In any case, the exclusion of fairness prior to the commencement of a formal decision-making process will normally be mitigated by the requirement to observe the duty at the formal decision-making stage.

Nevertheless, investigations and advisory processes may have a considerable impact on affected persons. For example, the reputation of anyone caught up in a public investigation may be adversely affected and the need for fairness protection will be clear.[28] Public inquiries may have significant consequences for those required to be involved and fairness protection will be provided here as well, often pursuant to legislation codifying the duty.[29] Fairness protection may be required for ostensibly preliminary decisions, where a formal determination is made subsequently, if the preliminary decision has de facto finality. For example, invariable acceptance by the ultimate decision-maker of the results of an investigation or advice from a preliminary decision-maker suggests that the real decision is being made at the preliminary stage, and in order for the duty of fairness to do its work, it should apply here.

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27 This limitation is reflected in the Ontario *Statutory Powers Procedure Act*, *supra* note 18, s. 3(2)(g): procedural requirements do not apply to "one or more persons required to make an investigation and to make a report, with or without recommendations, where the report is for the information or advice of the person to whom it is made and does not in any way legally bind or limit that person in any decision he or she may have power to make."

28 Human rights investigations are a good example. Where a commission has an investigative function and the authority to refer a matter to a tribunal for a formal hearing, fairness may be required at the investigative stage. See e.g. *Blencoe v. British Columbia (Human Rights Commission*, 2000 SCC 44, [2000] 2 S.C.R. 307 [*Blencoe*].

29 The Supreme Court discussed the basic fairness principles relevant to public inquiries in *Canada (Attorney General) v. Canada (Commission of Inquiry on the Blood System in Canada—Krever Commission)*, [1997] 3 S.C.R. 440. Peter Carver discusses the law of public inquiries in Chapter 16, Getting the Story Out: Accountability and the Law of Public Inquiries, and see, generally, Allan Manson & David Mullan, eds., *Commissions of Inquiry: Praise or Reappraise?* (Toronto: Irwin Law, 2003).

B. The Duty Does Not Apply to Legislative Decisions

The Supreme Court of Canada has long insisted that the duty of fairness does not apply to legislative decisions or functions.[30] In *Re Canada Assistance Plan (B.C.)*, the Court expressed the point categorically: "[T]he rules governing procedural fairness do not apply to a body exercising purely legislative functions."[31]

The Court has never explained what it means by "legislative" functions, but it is clear that primary legislation, whether passed by Parliament or a provincial legislature, is not subject to the duty of fairness. It is not exempt because it has no impact on rights, privileges, or interests. On the contrary, legislation is likely to have a profound impact for large numbers of people because it applies generally. It is exempt from the duty of fairness because any meaningful conception of a separation of powers between the legislature and the courts demands it. In *Reference re Resolution to Amend the Constitution*, the Court essayed the relationship between the legislature and the courts as follows:

> How Houses of Parliament proceed, how a provincial legislative assembly proceeds is in either case a matter of self definition, subject to any overriding constitutional or self-imposed statutory or indoor prescription. It is unnecessary here to embark on any historical review of the "court" aspect of Parliament and the immunity of its procedures from judicial review. Courts come into the picture when legislation is enacted and not before (unless references are made to them for their opinion on a bill or a proposed enactment). It would be incompatible with the self regulating—"inherent" is as apt a word—authority of Houses of Parliament to deny their capacity to pass any kind of resolution. Reference may appropriately be made to art. 9 of the *Bill of Rights* of 1689, undoubtedly in force as part of the law of Canada, which provides that "Proceedings in Parliament ought not to be impeached or questioned in any Court or Place out of Parliament."[32]

This rationale for exempting legislative functions from the duty of fairness was reiterated in *Wells v. Newfoundland*. In that case, the Newfoundland Legislature passed legislation abolishing a quasi-judicial position to which Wells had been appointed. Wells's argument that he should have been accorded procedural fairness was rejected summarily by the Court, which stated as follows:

> [L]egislative decision making is not subject to any known duty of fairness. Legislatures are subject to constitutional requirements for valid law-making, but within their constitutional boundaries, they can do as they see fit. The wisdom and value of legislative decisions are subject only to review by the electorate.[33]

There is no guarantee that political accountability will be meaningful, of course, but this is no concern of the courts. No one has the right to prevail in the political process, no matter

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30 *Attorney General of Canada v. Inuit Tapirisat*, [1980] 2 S.C.R. 735 at 757 [*Inuit Tapirisat*], citing *Bates v. Lord Hailsham*, [1972] 3 All E.R. 1019 (Ch. D.).

31 [1991] 2 S.C.R. 525 at para. 60.

32 [1981] 1 S.C.R. 753 at 785.

33 [1999] 3 S.C.R. 199 at para. 59. However, Wells succeeded in a contract suit against the Crown, the Court holding that the legislation abolishing his position had not abrogated his right to seek damages against the Crown for breach of his contract of employment.

how sympathetic his or her cause may seem, as *Authorson v. Canada (Attorney General)*[34] demonstrates. In that case, Parliament passed legislation retrospectively limiting the amount of money owed to disabled war veterans—decades of interest on pension and benefit funds—to whom the Crown owed fiduciary duties. The law affected thousands of veterans, none of whom was given notice of the proposed change to the law. In class action proceedings, Authorson argued that the legislation infringed the right not to be deprived of the enjoyment of property except by due process of law under the *Canadian Bill of Rights* (s. 1(a)), as well as the right to a fair hearing in accordance with the principles of fundamental justice for the determination of one's rights and obligations (s. 2(e)).

This argument succeeded at trial and in the Ontario Court of Appeal, but was given short shrift in the Supreme Court of Canada. The Court emphatically rejected the notion that the *Canadian Bill of Rights* established due process procedures with regard to the passage of legislation, and reiterated that the common law had nothing to add:

> The respondent claimed a right to notice and hearing to contest the passage of s. 5.1(4) of the *Department of Veterans Affairs Act*. However, in 1960, and today, no such right exists. Long-standing parliamentary tradition makes it clear that the only procedure due any citizen of Canada is that proposed legislation receive three readings in the Senate and House of Commons and that it receive Royal Assent. Once that process is completed, legislation within Parliament's competence is unassailable.[35]

If the rationale for the exemption of legislative functions is clear, however, the idea of exemption by category is problematic, because it recalls the long-discredited distinction between administrative and judicial or quasi-judicial decisions. It invites argument over the meaning of the term "legislative" and makes for all-or-nothing outcomes. If an applicant for judicial review succeeds in convincing a court that a decision is subject to the duty of fairness, the court will determine the required procedure and quash the decision if there has been a failure to observe it. But if the public authority succeeds in convincing the court that its actions are legislative in nature, then the duty of fairness will not apply and the court will have nothing to say about any procedures adopted or their adequacy.

The categorical exemption of legislative functions becomes especially problematic as it extends beyond primary legislation to include secondary legislation and policy decisions, both of which are discussed below.

1. Are Cabinet and Ministerial Decisions Covered by the Legislative Exemption?

Cabinet and ministerial decisions are not subject to the legislative exemption per se, but it will often be easy to characterize Cabinet and ministerial decisions as legislative in nature and, as a result, they will be exempted from the duty.

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34 2003 SCC 39, [2003] 2 S.C.R. 40 [*Authorson*].

35 *Ibid.* at para. 37. The Court held that the protection of s. 2(e) is limited to "the application of law to individual circumstances in a proceeding before a court, tribunal or similar body" (para. 61).

Attorney General of Canada v. Inuit Tapirisat provides a good example. In that case, the federal Cabinet rejected an appeal from a decision made by the Canadian Radio-television and Telecommunications Commission (CRTC) without allowing the petitioning group to be heard. The Cabinet heard from the utility and the CRTC and took advice from ministerial officials, but the petitioning group was essentially left out of the proceedings. Justice Estey considered the Cabinet's power to be legislative in nature, in part because the legislation authorized Cabinet to overturn a decision of the CRTC on its own motion. This, he said, was "legislative action in its purest form."[36] Estey J. buttressed this position by accentuating the practical difficulties inherent in extending the duty of fairness. He did not want to burden the Cabinet with hearing requirements and expressed concern about undermining the Cabinet's public policy-making role.

Inuit Tapirisat has been subject to extensive criticism on the basis that it overstates the difficulties inherent in applying the duty of fairness to Cabinet decisions. After all, the duty is flexible and its content could be tailored to address some of the concerns raised by Estey J.[37] (To take an obvious example, it is difficult to conceive of circumstances in which the Cabinet would be required to hold an oral hearing.) Moreover, the case for exempting Cabinet decisions from the duty of fairness may be thought weaker than the case for exempting primary legislation, because Cabinet decision making is not subject to political scrutiny in the same way. Nevertheless, it is not surprising to find the courts wary of scrutinizing the decisions of the executive branch of government, even for limited procedural purposes. The potential for conflict between the courts and the executive is great.

In other contexts, the Court has emphasized the unique role and responsibilities of the executive branch as a reason for not extending the duty of fairness to ministerial decisions. In *Idziak v. Canada (Minister of Justice)*, Justice Cory discussed the minister of justice's exercise of discretionary authority to issue a warrant of surrender in an extradition case as follows:

> Parliament chose to give discretionary authority to the Minister of Justice. It is the Minister who must consider the good faith and honour of this country in its relations with other states. It is the Minister who has the expert knowledge of the political ramifications of an extradition decision. In administrative law terms, the Minister's review should be characterized as being at the extreme legislative end of the *continuum* of administrative decision-making.[38]

Decisions involving particular individuals are most likely to give rise to the application of the duty of fairness to Cabinet and ministerial decisions, but, as *Idziak* demonstrates, even in this context the Court may be reluctant to impose procedural requirements for a variety of reasons.

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36 *Supra* note 30 at 754.

37 See e.g. *Minister for Arts, Heritage and Environment v. Peko-Wallsend Ltd.* (1987), 75 A.L.R. 218 (Fed. Ct., Aust.) (assuming that Cabinet decisions are subject to the duty of fairness, the ability to make a written submission to the responsible minister suffices). I am grateful to Matthew Groves for this reference.

38 [1992] 3 S.C.R. 631 at 659 (emphasis in original).

2. Is Subordinate Legislation Covered by the Legislative Exemption?

Political self-interest often ensures that consultation occurs prior to the passage of legislation, even where there is no formal requirement for it. There will, however, be times when it is not in the political interest to consult before legislating and the argument for fairness protection in these contexts may seem strong, especially with regard to subordinate legislation.[39]

Arguably, there is less reason to be concerned about judicial interference in the political process where subordinate legislation is concerned because subordinate legislation is made pursuant to executive authority and democratic accountability may be minimal. American experience with "notice and comment" requirements demonstrates that procedural requirements are not unworkable.[40] Nevertheless, as Andrew Green explains in greater detail in Chapter 4, Regulations and Rule Making: The Dilemma of Delegation, in general the courts have not imposed procedural requirements on the subordinate law-making function. Such requirements as exist in particular contexts have been established by legislation.

However, there are exceptions. For example, in the unique circumstances of *Homex Realty and Development Co. v. Wyoming (Village)*,[41] the Supreme Court of Canada concluded that passage of a municipal bylaw was subject to the duty of fairness. It did so because it was clear that the village's motivation for passing the bylaw was an ongoing dispute it had with a particular developer. In these circumstances, the Court held that the village was not allowed

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39 Geneviève Cartier, "Procedural Fairness in Legislative Functions: The End of Judicial Abstinence?" (2003) 53 U.T.L.J. 217.

40 *Administrative Procedures Act*, 5 U.S.C. § 553 provides as follows:

> (a) This section applies, according to the provisions thereof, except to the extent that there is involved—
> (1) a military or foreign affairs function of the United States; or
> (2) a matter relating to agency management or personnel or to public property, loans, grants, benefits, or contracts.
> (b) General notice of proposed rule making shall be published in the Federal Register, unless persons subject thereto are named and either personally served or otherwise have actual notice thereof in accordance with law. The notice shall include—
> (1) a statement of the time, place, and nature of public rule making proceedings;
> (2) reference to the legal authority under which the rule is proposed; and
> (3) either the terms or substance of the proposed rule or a description of the subjects and issues involved.
> Except when notice or hearing is required by statute, this subsection does not apply—
> (A) to interpretative rules, general statements of policy, or rules of agency organization, procedure, or practice; or
> (B) when the agency for good cause finds (and incorporates the finding and a brief statement of reasons therefor in the rules issued) that notice and public procedure thereon are impracticable, unnecessary, or contrary to the public interest.
> (c) After notice required by this section, the agency shall give interested persons an opportunity to participate in the rule making through submission of written data, views, or arguments with or without opportunity for oral presentation. After consideration of the relevant matter presented, the agency shall incorporate in the rules adopted a concise general statement of their basis and purpose ... .

See, generally, Peter L. Strauss, *Administrative Justice in the United States*, 2d ed. (Durham, N.C.: Carolina Academy Press, 2002) at 220-22.

41 [1980] 2 S.C.R. 1011 [*Homex Realty*].

to couch its actions in a form designed to oust the application of the duty of fairness.[42] This makes the point that substance is more important than form where the legislative exemption is concerned.

3. Are Policy Decisions Covered by the Legislative Exemption?

The legislative exemption includes decisions that may be described as "policy" decisions as well as decisions that are general in nature. In *Martineau v. Matsqui Institution Disciplinary Board*, Justice Dickson observed that "[a] purely ministerial decision, on broad grounds of public policy, will typically afford the individual no procedural protection."[43] In *Knight v. Indian Head School Division No. 19*, Justice L'Heureux-Dubé noted that many administrative bodies have been required to assume duties traditionally performed by legislatures, and distinguished "decisions of a legislative and general nature" from "acts of a more administrative and specific nature."[44]

The rationale for exempting policy decisions from the duty is similar to that of formal legislative decisions. Both are inherently political in nature and are, in principle, subject to political accountability. Thus, in *Imperial Oil Ltd. v. Quebec (Minister of the Environment)*, the Supreme Court held that in exercising discretionary power to require an oil company to undertake site decontamination measures (at its own expense), Quebec's environment minister was performing a political role in choosing from among the policy options allowed under provincial environmental protection legislation and was not subject to fairness obliga-

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42 The majority of the Court characterized the bylaw as quasi-judicial rather than legislative in substance. Justice Dickson (dissenting on the remedial point) put the case for procedural fairness protection more simply, *ibid.* at 1052-53:

> What we have here is not a by-law of wide and general application which was to apply to all citizens of the municipality equally. Rather, it was a by-law aimed deliberately at limiting the rights of one individual, the appellant Homex. In these circumstances, I would hold that Homex was entitled to some procedural safeguards. This does not mean that the municipality was under a duty to observe the procedures appropriate to a court of law. But, at a minimum, it was under a duty to give Homex notice of the proposed by-law and the opportunity to be heard.

In *Catalyst Paper Corp. v. North Cowichan (District)*, 2012 SCC 2, the Court asserted that the requirements of procedural fairness and legislation governing a municipality "may require that the municipality comply with certain procedural requirements, such as notice or voting requirements" (para. 12) and did not mention *Homex*. However, the Court went on to say that municipalities make quasi-judicial as well as legislative decisions and that the two are treated differently:

> Formal reasons may be required for decisions that involve quasi-judicial adjudication by a municipality. But that does not apply to the process of passing municipal bylaws. ... The reasons for a municipal bylaw are traditionally deduced from the debate, deliberations and the statements of policy that give rise to the bylaw. ... [T]he municipality is [not] required to formally explain the basis of a bylaw. (paras. 29-30)

43 [1980] 1 S.C.R. 602 at 628, cited with approval in *Re Canada Assistance Plan (B.C.)*, [1991] 2 S.C.R. 525 at para. 60.

44 [1990] 1 S.C.R. 653 at para. 26 [*Indian Head School*].

tions beyond those in the Act.[45] Governments are elected to make policy decisions and must be allowed to do so, provided that they comply with relevant constitutional requirements.

But acceptance of the political rationale does not resolve the difficulties surrounding the exemption of policy decisions. Although legislative functions may be identified by the formalities that surround the legislative process, it can be considerably more difficult to identify a policy decision. Moreover, given different judicial perceptions about institutional roles, accountability, and legitimacy, we should expect to find inconsistent decisions. In truth, it is easy for a court to characterize a decision as a policy decision if it simply does not want to interfere in a particular case.

C. The Duty Does Not Apply to Public Office Holders Employed Under Contracts

Although the duty of fairness developed in the context of public office holders in cases such as *Nicholson* and *Indian Head School*, in *Dunsmuir v. New Brunswick*[46] the Court overruled its earlier approach and held that the law will no longer draw a distinction between public office holders and other employees in dismissal cases. If the terms of an individual's employment are governed by contract, then ordinary private law contractual remedies will apply in the event of his or her dismissal, regardless of the public nature of the employment concerned. By abandoning the distinction between public office holders and contractual employees, the Court hoped to simplify the application of the law, obviating the need for litigation concerning the nature of an individual's employment.[47]

Following *Dunsmuir*, it will be assumed that a contract of employment addresses procedural fairness issues. If it does not, the normal common- or civil-law principles will govern. In either event, protection from wrongful dismissal will be governed by private law contract principles. The Court conceived of two exceptions. First, employees not protected by employment contracts, or subject to employment at pleasure, will still be protected by the duty of fairness. Second, the duty of fairness may arise by necessary implication in some statutory contexts.

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45 [2003] 2 S.C.R. 624, [2003] 2 S.C.R. 624 [*Imperial Oil*]. The *Environment Quality Act*, R.S.Q., c. Q-2, s. 31.42 provided procedural protection, including a requirement that notice be given to interested persons and that reasons for the decision be given. The Court's remarks concerning the nature of the minister's decision were made in the context of an argument that the minister was not impartial, and as a result, was in breach of the bias rule of the duty of fairness.

46 *Supra* note 9.

47 Nevertheless, *Dunsmuir* necessarily limits the protection of public employees to some extent. It will no longer be possible for public office holders to be restored to their positions, because that remedy is not available for breach of contract. The Court acknowledges as much, but argues that the duty of fairness did not include a reinstatement remedy, given that public office holders could be dismissed provided only that the proper procedures were followed. There is no doubt, however, that reinstatement to a position following a breach of the duty of fairness—even on an ostensibly temporary basis while a new decision is waiting to be made—was a considerable motivation for bringing judicial review proceedings.

D. The Duty May Be Suspended or Abridged in the Event of an Emergency

The duty of fairness establishes duties that must be observed *before* a decision can be made. There will, however, sometimes be circumstances in which procedural requirements cannot be met without risking harm of one sort or another.

In an emergency situation, compliance with the duty of fairness may be suspended until after the required decision has been made. For example, in *Cardinal v. Director of Kent Institution*, the Court held that although the duty of fairness applied to the imposition of isolation or segregation of prison inmates in "apparently" urgent or emergency circumstances (the inmates alleged to have been involved in a hostage taking were transferred to another institution and placed in isolation to secure prison order), "there could be no requirement of prior notice and an opportunity to be heard before the decision. ... [T]he process of prison administration, because of its special nature and exigencies, should not be unduly burdened or obstructed by the imposition of unreasonable or inappropriate procedural requirements."[48] However, once a recommendation to end the segregation of prisoners had been made by the review body, the duty of fairness required that the prison director inform the inmates of his intended decision to reject the recommendation, provide reasons, and afford them an opportunity to contest his intended decision. The Court regarded this as a minimal amount of fairness that would not undermine the administration of the prison.

To what extent will a court defer to a decision-maker as to the existence of circumstances justifying the suspension or abridgment of fairness? Deference to the government in regard to national security matters is to be expected, but care must be taken to ensure that public authorities are not overzealous in apprehending urgent or emergency circumstances. There should be few cases in which minimal fairness procedures cannot be provided before a decision is made.

V. The Content of the Duty of Fairness

As we have seen, the extension of the duty of fairness to a wide range of administrative decisions in *Nicholson* was facilitated by the decision to make the content of duty flexible and context-specific. Thus, fairness requires compliance with some, but not necessarily all, of the requirements of natural justice.[49] Fairness is a *minimum* duty that must be met—a floor for procedural protection rather than a ceiling. In determining whether the duty of fairness has been met, courts ask whether the procedural protection provided in particular circumstances was adequate, not ideal.[50]

Consider the position of those involved in the following three scenarios and the scope of the procedural protection that is appropriate in each.

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48 *Supra* note 10 at paras. 16, 22.

49 *Martineau v. Matsqui Inmate Disciplinary Board*, [1980] 1 S.C.R. 602 at 630.

50 As Justice Evans put it in *Waycobah First Nation v. Attorney General of Canada*, 2011 FCA 191 at para. 32, "[T]he duty of fairness affords individuals an adequate, not the optimum, opportunity to inform the decision-maker of their case."

1. *Criminal law prosecution.* The criminal law provides a good point of comparison for procedural fairness in administrative law. The stakes for a person charged with a criminal offence are high. Accused persons are at risk of losing their liberty and are subject to significant consequences, both direct and indirect, as a result of the charges they face. In these circumstances, nothing less than full procedural protection will do: an accused person is entitled to a formal, oral hearing before an independent and impartial judge. This protection has long been afforded and is now codified in the Charter (s. 11(d)), which also includes the following protection:

   - the right to be informed of the offence (11(a)),
   - the right to be tried within a reasonable time (11(b)),
   - disclosure of the evidence and case to be met,[51]
   - the right to counsel (10(b)),
   - the right to call evidence and cross-examine witnesses,
   - the presumption of innocence (10(d)), and
   - a written decision with reasons.[52]

   None of these protections is controversial in the context of criminal law, but some have little relevance in the context of administrative proceedings. Administrative proceedings are typically informal, do not involve oral hearings, and do not take place before judges. Although some administrative proceedings have much in common with a criminal proceeding (for example, disciplinary hearings in professional contexts), in general, a lower standard of protection will usually suffice.

2. *Human rights adjudication.* Human rights legislation is designed to be remedial rather than punitive, so, in principle, the stakes for a respondent to a human rights complaint are lower than for an accused person facing a criminal charge. But the consequences may nevertheless be significant: consider the possible harm to reputation a respondent may suffer by being accused of an act of discrimination; the costs in terms of time and money of defending a complaint; and the damages the respondent may ultimately be ordered to pay by a human rights tribunal. Given these possible repercussions, the respondent will want to test the evidence against him or her, and in order to do so, an oral hearing with many of the protections available in the context of criminal prosecution is required. But some of those protections will apply in attenuated form. For example, human rights litigation usually takes place before tribunals whose members may be part-time or fixed-term appointees who do not enjoy the high level of independence that judges do,[53] and the proceedings are less formal in nature. But the essence of the matter will be the same: the respondent to a human rights complaint is entitled to be represented by counsel and has the right, for example, to call evidence, cross-examine witnesses, and make

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51 *R. v. Stinchcombe*, [1991] 3 S.C.R. 326 [*Stinchcombe*].

52 *R. v. REM*, 2008 SCC 51, [2008] 3 S.C.R. 3.

53 See the indicia of independence set out in *Valente v. The Queen*, [1985] 2 S.C.R. 673, including security of tenure, financial security, and institutional independence.

and reply to arguments. Such procedures may be set out in the legislation or accompanying rules or regulations, but to the extent that they are not, they will be governed by the duty of fairness.

3. *Licensing regulation.* Consider a regulated industry in which possession of a licence is required in order to work. Those in the industry have an important interest in obtaining and maintaining their licences, but it does not follow that they are entitled to an oral hearing on all licensing matters. The importance of the matter is a consideration, but the needs of the state must also be considered. Oral hearings are expensive and time-consuming, and will not ordinarily be necessary to deal fairly with a licence application. Indeed, in a straightforward case it will ordinarily be enough to allow an applicant to apply for a licence by completing an application form and providing the required information, following which a decision can be made based on consideration of the relevant criteria.

   It is not difficult to imagine circumstances in which greater fairness might be required. Suppose, for example, that a licensing authority has information that raises concerns about an applicant's fitness to be granted, or to continue to hold, a licence, and that the authority proposes to rely on that information to deny the applicant's licence application or to revoke an existing licence. In these circumstances, the licensing authority should at least inform the applicant of the information and invite submissions in reply. Depending on the nature of the information, additional procedural protection may be required.

Duty of fairness concerns are least likely to arise in the context of tribunals required to provide oral hearings, because the procedure for those hearings is usually clear. Some tribunals operate pursuant to detailed legislation that establishes procedural requirements; others are empowered to establish their own procedures in secondary legislation. The Ontario Labour Relations Board is a good example of the latter approach. The chair of the Board has rule-making authority and the Board has developed its own procedural code.[54] The Canadian Transportation Agency is another example of a tribunal that has the authority to control its processes and make its own procedural rules.[55] Still other tribunals may operate pursuant to general statutory mandates such as that established by the Ontario *Statutory Powers Procedure Act*,[56] which establishes minimum default procedural provisions for Ontario tribunals required to provide oral hearings.

For a large range of administrative decision-makers, however, common-law considerations govern the scope and content of the duty of fairness. The leading case, *Baker*, is discussed below.

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54 *Labour Relations Act*, S.O. 1995, c. 1, Sch. A, s. 110(17).

55 *Canada Transportation Act*, S.C. 1996, c. 10, s. 17.

56 R.S.O. 1990, c. S.22.

A. Baker v. Canada (Minister of Citizenship and Immigration)[57]

Mavis Baker was a visitor from Jamaica who remained in Canada as an illegal immigrant. She was employed as a live-in domestic worker for 11 years and during that time had four children, all of whom acquired Canadian citizenship by birth. In 1992 she was ordered to be deported. Immigration legislation required applicants for permanent residence to apply from outside Canada, meaning that Ms. Baker would have to apply from Jamaica. She applied for an exemption from this requirement pursuant to regulations that provided as follows:

> The Minister is hereby authorized to exempt any person from any regulation made under subsection 114(1) of the Act or otherwise facilitate the admission to Canada of any person where the Minister is satisfied that the person should be exempted from that regulation or that person's admission should be facilitated owing to the existence of compassionate or humanitarian considerations.[58]

Baker argued she had psychiatric problems that might worsen if she were forced to return to Jamaica. Moreover, two of her Canadian-born children depended on her for their care, and she was in regular contact with the other two. They, and she, would suffer emotional hardship if she were forced to return to Jamaica.

The discretionary power involved in assessing compassionate and humanitarian considerations was exercised in the name of the minister by an immigration officer. That officer denied Baker's request for an exemption on the advice of another officer, Officer Lorenzo, whose written memorandum was provided to Baker and is set out below:

> PC is unemployed—on Welfare. No income shown—no assets. Has four Cdn.-born children—four other children in Jamaica—HAS A TOTAL OF EIGHT CHILDREN.
>
> Says only two children are in her "direct custody." (No info on who has ghe [sic] other two.)
>
> There is nothing for her in Jamaica—hasn't been there in a long time—no longer close to her children there—no jobs there—she has no skills other than as a domestic—children would suffer—can't take them with her and can't leave them with anyone here. Says has suffered from a mental disorder since '81—is now an outpatient and is improving. If sent back will have a relapse.
>
> Letter from Children's Aid—they say PC has been diagnosed as a paranoid schizophrenic.—children would suffer if returned—
>
> Letter of Aug. '93 from psychiatrist from Ont. Govm't.
>
> Says PC had post-partum psychosis and had a brief episode of psychosis in Jam. when was 25 yrs. old. Is now an out-patient and is doing relatively well—deportation would be an extremely stressful experience.
>
> Lawyer says PS [sic] is sole caregiver and single parent of two Cdn. born children. PC's mental condition would suffer a setback if she is deported etc.
>
> This case is a catastrophy [sic]. It is also an indictment of our "system" that the client came as a visitor in Aug. '81, was not ordered deported until Dec. '92 and in APRIL '94 IS STILL HERE!

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57 [1999] 2 S.C.R. 817 [*Baker*].

58 *Immigration Regulations, 1978*, SOR/78-172, as am. by SOR/93-44.

> The PC is a paranoid schizophrenic and on welfare. She has no qualifications other than as a domestic. She has FOUR CHILDREN IN JAMAICA AND ANOTHER FOUR BORN HERE. She will, of course, be a tremendous strain on our social welfare systems for (probably) the rest of her life. There are no H&C factors other than her FOUR CANADIAN-BORN CHILDREN. Do we let her stay because of that? I am of the opinion that Canada can no longer afford this type of generosity. However, because of the circumstances involved, there is a potential for adverse publicity. I recommend refusal but you may wish to clear this with someone at Region.
>
> There is also a potential for violence—see charge of "assault with a weapon." [Capitalization in original.]

Baker sought judicial review of the minister's decision, arguing among other things that the minister failed to observe the requirements of the duty of fairness. She argued that she should have been granted an oral interview before the decision-maker; that her children and their fathers should have been given notice of the interview; that they should have been allowed to make submissions at the interview; and that the fathers of her children should have been given permission to attend the interview with counsel. She argued, in addition, that she was entitled to reasons for the minister's decision and that the immigration officer's notes gave rise to a reasonable apprehension of bias. The decision to deny Baker's application was upheld in the Federal Court and she appealed to the Supreme Court of Canada.

The Supreme Court of Canada held that Baker was entitled procedural fairness protection, but the content of the duty was minimal in the circumstances. An oral hearing was not required. It was enough that she was permitted to submit complete written documentation and that reasons for the minister's decision were provided—albeit that the Court accepted the immigration officer's memorandum to another officer fulfilled the reasons requirement.[59]

For present purposes, the important point is that the Court used *Baker* as the occasion to reiterate the purpose of the duty of fairness and set out a number of criteria relevant to determining its content. Justice L'Heureux-Dubé described the purpose of the duty of fairness as follows:

> [T]he purpose of the participatory rights contained within the duty of procedural fairness is to ensure that administrative decisions are made using a fair and open procedure, appropriate to the decision being made and its statutory, institutional, and social context, with an opportunity for those affected by the decision to put forward their views and evidence fully and have them considered by the decision-maker.[60]

Baker follows on from L'Heureux-Dubé J.'s decision in *Indian Head School Division*, in which she argued that the duty of fairness was "entrenched in the principles governing our

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59 Officer Lorenz's notes were provided in response to Baker's counsel's request for reasons, and in the absence of any other record, the Court treated them as the reasons for the decisions. The conclusion that the notes revealed bias was enough to quash the decision, but the Court went on to hold that the minister's discretionary decision was subject to review for reasonableness, and was not reasonable because it paid insufficient attention to the interests and needs of the children and the hardship that a return to Jamaica might cause Ms. Baker. The decision was also quashed on this basis and remitted for reconsideration.

60 *Baker*, *supra* note 57 at para. 22.

legal system."[61] At the same time, however, she emphasized the importance of respecting the needs of administrative decision-makers:

> It must not be forgotten that every administrative body is the master of its own procedure and need not assume the trappings of a court. The object is not to import into administrative proceedings the rigidity of all the requirements of natural justice that must be observed by a court, but rather to allow administrative bodies to work out a system that is flexible, adapted to their needs and fair. As pointed out by de Smith, the aim is not to create "procedural perfection" but to achieve a certain balance between the need for fairness, efficiency and predictability of outcome.[62]

The criteria set out in *Baker* are designed to give effect to these aims.

B. The Baker Synthesis

L'Heureux-Dubé J. enumerated five criteria relevant to determining the content of the duty of fairness in particular circumstances:

1. the nature of the decision being made and the process followed in making it;
2. the nature of the statutory scheme and the terms of the statute pursuant to which the body operates;
3. the importance of the decision to the individual or individuals affected;
4. the legitimate expectations of the person challenging the decision; and
5. the choices of procedure made by the agency itself.[63]

L'Heureux-Dubé J. did not intend these criteria to be exhaustive and the Court has recently reiterated as much. In *Canada (Attorney-General) v. Mavi*, Justice Binnie noted:

> [T]he obvious point is that the requirements of the duty in particular cases are driven by their particular circumstances. The simple overarching requirement is fairness, and this "central" notion of the "just exercise of power" should not be diluted or obscured by jurisprudential lists developed to be helpful but *not* exhaustive.[64]

It is important to note, too, that none of the *Baker* criteria is, in theory, more important than any other. It is not unusual for courts to conclude that some criteria support a high degree of procedural protection in particular circumstances while others suggest that a lower degree of protection suffices. In every case, courts must determine the requirements of the duty of fairness protection by making an overall appraisal of the circumstances.

Each of the criteria set out in *Baker* is addressed below.

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61 *Indian Head School*, *supra* note 44 at para. 46.

62 *Ibid.* at para. 49 (internal citation omitted).

63 *Baker*, *supra* note 57 at paras. 23-27.

64 2011 SCC 30, [2011] 2 S.C.R. 504 para. 42 (emphasis in original).

1. The Nature of the Decision Being Made and the Process Followed in Making It

Although the classification of decisions as judicial, quasi-judicial, or administrative is no longer important in determining the threshold question—*whether* procedural protection must be provided—decisions that are considered judicial or quasi-judicial in nature are likely to demand more extensive procedural protection than administrative decisions. L'Heureux-Dubé J. put the point this way: "The more the process provided for, the function of the tribunal, the nature of the decision-making body, and the determinations that must be made to reach a decision resemble judicial decision making, the more likely it is that procedural protections closer to the trial model will be required by the duty of fairness."[65]

Given that the development of the duty of fairness was predicated on the irrelevance of the nature of the decision in question, it may seem odd that the nature of the decision remains relevant to determining the content of the duty. However, the nature of the decision is only one of several considerations and it will often be uncontroversial. For example, greater procedural protection is likely to be required in an adjudicative context than a regulatory one.

2. The Nature of the Statutory Scheme and the Terms of the Statute Pursuant to Which the Body Operates

It is important to pay close attention to the legislation that authorizes a particular decision to be made. The requirements of fairness may be minimal in the context of steps that are preliminary to a formal decision-making process. For example, as noted above, investigatory procedures are not normally subject to the duty of fairness even though they might give rise to proceedings in which fairness protection will be required. Greater fairness protection will usually be required if a final decision must be made, but a decision need not be final in order to attract a high degree of fairness protection. Enhanced procedural protection may be required if a second level of proceedings is envisaged, in order to allow meaningful participation in those proceedings. For example, the existence of a right of appeal is an important consideration in deciding whether and to what extent reasons for a first-level decision are required.

3. The Importance of the Decision to the Individual or Individuals Affected

The content of the duty of fairness increases in proportion to the importance of the particular decision to the person it affects. L'Heureux-Dubé J. referred to the context of employment in making this point, citing Justice Dickson's observation in *Kane v. Bd. of Governors of U.B.C.* that "[a] high standard of justice is required when the right to continue in one's

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65 *Baker*, *supra* note 57 at para. 23.

66 [1980] 1 S.C.R. 1105 at 1113.

profession or employment is at stake."[66] However, many things short of adverse impact on one's career or livelihood may support claims for greater procedural protection.

4. The Legitimate Expectations of the Person Challenging the Relevant Decision

The doctrine of legitimate expectation may extend the content of the duty of fairness on the basis of the conduct of public authorities in particular circumstances. For example, a person might be led to understand that he or she will be afforded particular procedural protection, such as an oral hearing before a particular decision is made, even though that level of protection would not otherwise be required. In these circumstances, the person may have a legitimate expectation that an oral hearing will be held and, if this is so, the public authority will be required to hold an oral hearing before the relevant decision can be made.

Legitimate expectation began as a threshold inquiry—a means of extending the applicability of the duty of fairness—but in *Baker* the Court subsumed the concept within the considerations relevant to determining the content of the duty.[67] Legitimate expectations of procedural protection may arise out of conduct such as representations, promises, or undertakings or past practice or current policy of a decision-maker. The Court summarized the concept in this way in *Canada (Attorney General) v. Mavi*:

> Where a government official makes representations within the scope of his or her authority to an individual about an administrative process that the government will follow, and the representations said to give rise to the legitimate expectation are clear, unambiguous and unqualified, the government may be held to its word, provided the representations are procedural in nature and do not conflict with the decision maker's statutory duty. Proof of reliance is not a requisite.[68]

More controversially, a legitimate expectation may also arise if a person is led to expect a particular *outcome* from a decision-making process. A public authority might have policies that suggest such an outcome, or perhaps an official may give an undertaking that a particular decision will be made. For example, an undertaking that a licence will be granted may give rise to a legitimate expectation that a person will receive a licence.

However, a legitimate expectation that a particular decision will be made, as opposed to an expectation that a particular procedure will be followed in making a decision, raises different concerns. Fundamentally, public authorities must be entitled to change their minds; indeed, they may sometimes be required to do so to protect the public interest. As a result,

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67 *Supra* note 57 at para. 26. The inspiration for the legitimate expectation argument in *Baker* came from the controversial decision of the High Court of Australia in *Minister for Immigration and Ethnic Affairs v. Teoh* (1995), 183 C.L.R. 273, in which a majority of that Court held that Australia's ratification of the International Convention on the Rights of the Child gave rise to a legitimate expectation that the best interests of the child would be a primary consideration for the minister in making discretionary decisions on deportation. However, *Teoh* is not mentioned in the Court's decision in *Baker*.

68 [2011] 2 S.C.R. 504 at para. 68 [*Mavi*].

the doctrine of legitimate expectation does not require that expectations of particular substantive outcomes must be fulfilled. In the example above, there is no entitlement to the grant of the licence. However, before a legitimate expectation of receiving a licence can be dashed, the person given the undertaking will be entitled to enhanced procedural fairness protection. For example, he or she may be entitled to notice of the intention not to grant the licence and a right to make submissions before the decision to deny the licence is made.

The concept of legitimate expectation is akin to promissory estoppel, an equitable doctrine that offers relief from reliance on promises that do not give rise to enforceable contracts,[69] but there are important differences.[70] The Supreme Court of Canada has on several occasions reiterated that a legitimate expectation affords only procedural protection, whereas a successful claim of estoppel may result in the enforcement of substantive promises.[71]

5. The Choices of Procedure made by the Agency Itself

The content of the duty of fairness affects more than just the person whose rights, privileges, or interests are at stake in a particular case. It also affects the decision-maker, who may be required to make decisions in hundreds, if not thousands, of additional cases and all those whose rights, privileges, or interests will be affected by those decisions. If the Court is to establish a workable standard, the procedural choices made by the decision-maker must be taken into account in determining the requirements of the duty of fairness. After all, the decision-maker will have superior knowledge of not only its needs but also the needs of the community it serves, and its procedural choices are worthy of respect as a result. As the Court noted in *Baker*:

> [T]he analysis of what procedures the duty of fairness requires should also take into account and respect the choices of procedure made by the agency itself, particularly when the statute leaves to the decision-maker the ability to choose its own procedures, or when the agency has an expertise in determining what procedures are appropriate in the circumstances. While this,

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69 See, generally, Stephen M. Waddams, *The Law of Contracts*, 6th ed. (Aurora, ON: Canada Law Book, 2010) at paras. 195-206. Estoppel is understood as a defensive concept—a "shield" rather than a "sword"—and, in general, does not result in the enforcement of non-contractual promises.

70 Justice Binnie discusses the differences between estoppel, which he suggests may rarely be available in public law contexts, and legitimate expectation in his concurring opinion in *Mount Sinai Hospital Center v. Quebec (Minister of Health and Social Services)*, 2001 SCC 41, [2001] 2 S.C.R. 281.

71 Note that English law has taken a different path. English courts have come to allow substantive expectations to be protected by the doctrine, rather than simply procedural expectations, and the process–substance distinction has become blurred. The leading case is *R. v. North and East Devon Health Authority, ex p. Coughlan*, [2001] Q.B. 213 (C.A.). Timothy Endicott argues that *Coughlan* is not an unusual or problematic decision. On his account, legitimate expectation must embrace substantive protection, and the substantive protection afforded by the doctrine can be explained as an example of *Wednesbury* unreasonableness—i.e., no reasonable public authority can exercise discretionary power to disappoint a legitimate expectation because to do so would be to abuse its power. At the same time, however, he recognizes that the protection afforded by the doctrine must be tempered with comity toward administrative authorities and that judges should defer to good reasons for disappointing a legitimate expectation. See Endicott, *Administrative Law*, 2d ed. (Oxford: Oxford University Press, 2011) 289-95.

> of course, is not determinative, important weight must be given to the choice of procedures made by the agency itself and its institutional constraints.[72]

Thus, one of the important tasks for decision-makers in responding to applications for judicial review is to educate the court as to the needs of their processes, which may reflect compromises necessary to allow decisions to be made within a reasonable time frame and at a reasonable cost.

It is not clear how significant the procedural choices of decision-makers will turn out to be in determining the content of procedural fairness protection. L'Heureux-Dubé J. stated that "important weight" must be given to the decision-maker's choice of procedure, but this provides little meaningful guidance, especially if the other criteria support claims to greater procedural protection.

C. Specific Components of the Duty of Fairness

Although most of the procedural rights protected by the duty of fairness are well established, their parameters are open to argument in particular contexts. Some of the most important aspects of the duty of fairness are discussed below.

1. Notice

Notice is the most basic aspect of the duty of fairness. It is the starting point for participation in any decision-making process and involves consideration of the following questions:

> Who is proposing to make a decision?
> What is the nature of the decision to be made?
> When will the decision be made?
> Where will the decision be made?
> Why is the decision being made?
> How is the decision to be made?

The requirements of notice are often prescribed in a tribunal's rules of procedure or in legislation governing hearing procedures. Where they are not, litigation may arise over questions concerning the timeliness and sufficiency of notice. Was it timely, in the sense that it provided adequate time to allow the recipient to respond? Did it provide sufficient information to allow the recipient to make an informed response? The overarching requirement of the duty of fairness is the idea of reasonableness. Thus, the general rule has aptly been stated as follows: "[N]otice must be adequate in all circumstances in order to afford to those concerned a reasonable opportunity to present proofs and arguments, and to respond to those presented in opposition."[73]

The requirement to provide notice should be understood as an ongoing duty: it arises prior to the making of a decision and continues throughout the course of a decision-making

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72 *Baker*, *supra* note 57 at para. 27 (internal citations omitted).

73 Donald J.M. Brown & John M. Evans, *Judicial Review of Administrative Action in Canada*, looseleaf (Toronto: Canvasback, 1998), vol. 2 at 1200 [Brown & Evans].

process. A party whose rights, privileges, or interests are at stake is entitled to participate meaningfully in the decision-making process, and in order to do so must be kept apprised of any relevant issues that arise during the course of a hearing.

2. Disclosure

Must information held by a decision-maker be disclosed in order to ensure a fair decision-making process? If so, how much?

The concept of disclosure is well known in the context of the criminal law. In *R. v. Stinchcombe*, the Supreme Court of Canada held that the Crown must disclose "all relevant material" to the defence in a criminal prosecution.[74] This decision flowed from the nature of the prosecution process and, in particular, the notion that the role of the prosecution is not to secure conviction, but, instead, to put all the relevant evidence before the court to ensure that there is a fair trial. As Justice Sopinka put it, "the fruits of the investigation which are in the possession of counsel for the Crown are not the property of the Crown for use in securing a conviction but the property of the public to be used to ensure that justice is done. In contrast, the defence has no obligation to assist the prosecution and is entitled to assume a purely adversarial role toward the prosecution."[75]

Proponents of administrative justice soon argued that the *Stinchcombe* disclosure principle ought to apply in administrative law, but this was rejected by the Court in *May v. Ferndale Institution*:

> It is important to bear in mind that the *Stinchcombe* principles were enunciated in the particular context of criminal proceedings where the innocence of the accused was at stake. Given the severity of the potential consequences the appropriate level of disclosure was quite high. In these cases, the impugned decisions are purely administrative. These cases do not involve a criminal trial and innocence is not at stake. The *Stinchcombe* principles do not apply in the administrative context.[76]

Although this appears to be a categorical rejection of the *Stinchcombe* principle in administrative law, the Court made clear that "the duty of procedural fairness generally requires that the decision-maker discloses the information he or she relied upon. The requirement is that the individual must know the case he or she has to meet."[77] Thus, the question is not *whether* disclosure is required in administrative proceedings, but *how much* disclosure is required in particular proceedings?[78]

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74 *Supra* note 51.

75 *Ibid.* at para. 12.

76 2005 SCC 82, [2005] 3 S.C.R. 809 at para. 91, per LeBel and Fish JJ.

77 *Ibid.* at para. 92.

78 Disclosure of information held by the public authority may be distinguished from the concept of discovery, which refers to information held by an opposing party involved in litigation. As Freya Kristjanson and Leslie McIntosh note, discovery is unusual in the context of administrative proceedings and gives rise to a number of concerns for counsel in arguing a case. See the discussion by Freya Kristjanson and Leslie McIntosh in Chapter 6, Advocacy Before Administrative Tribunals.

Tribunals required to hold oral hearings are likely to have disclosure obligations spelled out in rules that govern their procedures or in generic procedural statutes such as Ontario's *Statutory Powers Procedure Act*. But there is considerable scope for the duty of fairness to require disclosure on an ad hoc basis, and courts have held that some circumstances, such as professional discipline and the possibility of a loss of livelihood, require a high level of disclosure.[79]

It is often argued that disclosure obligations must be tempered or limited by the needs of the authorities in particular circumstances or the rights of other persons. For example, in parole hearings or prison discipline cases, there may be concerns about the personal safety of informants and a need to keep their identity secret. Criminal investigative material—for example, wiretap and search warrant information[80] and sensitive national security information[81]—may also need to be kept confidential.

How is fairness to be maintained in these circumstances? The answer is that the disclosure duty can be tailored to the needs of particular circumstances. Information can be vetted by a court to determine its materiality and relevance and may be disclosed only to counsel, with instructions limiting its further dissemination. Disclosure after the fact, along with judicial review and rights of appeal, may mitigate any fairness concerns, as the Court suggested in *Ruby v. Canada (Solicitor General)*.[82] Ultimately, the duty of fairness is satisfied if a party has sufficient information to make informed submissions in regard to a particular matter.

3. Oral Hearings

Oral hearings are often demanded, but seldom required. They are not usually necessary to reach an informed decision on an administrative matter and there are good reasons for not granting them, including the expense and delay they occasion. The administrative process would grind to a halt if the duty of fairness required an oral hearing before any decision could be made.

In what circumstances will the common law require that an oral hearing be provided, as opposed to a hearing "on the papers"? The short answer is that it depends on the relevant circumstances. Nevertheless, some of the circumstances in which an oral hearing will be required are well settled. For example, an oral hearing will be required where a decision depends on findings of witness credibility. This was the basis for the Supreme Court's decision in *Singh v. Minister of Employment and Immigration*,[83] in which the Court held that a person claiming Convention refugee status was entitled to an oral hearing. That was because refugee status depended on whether claimants had a "well-founded fear of persecution" in their homeland, and this was not something that could be sorted out on the basis of a paper

79 See e.g. *Sherriff and Attorney General for Canada*, 2006 FCA 139.

80 *Ruby v. Canada (Solicitor General)*, 2002 SCC 75, [2002] 4 S.C.R. 3 [*Ruby*].

81 See e.g. *Charkaoui v. Canada (Citizenship and Immigration)*, 2007 SCC 9, [2007] 1 S.C.R. 350 and *Charkaoui v. Canada (Citizenship and Immigration)*, 2008 SCC 38, [2008] 2 S.C.R. 326.

82 *Supra* note 80.

83 [1985] 1 S.C.R. 177.

hearing. Claimants had to be given the opportunity to provide evidence in person—to tell their story—not simply because of the importance of the matter to them, but also because the decision-making authorities could not determine factually disputed evidence without seeing and hearing from the claimant.

Singh was decided under both s. 7 of the Charter and s. 2(e) of the *Canadian Bill of Rights*, because the legislation in question specifically denied an oral hearing. Where legislation does not preclude an oral hearing, however, recourse to constitutional and quasi-constitutional remedies will not be necessary. The common law may require that an oral hearing be held.[84]

4. Right to Counsel

There is no right to counsel in the context of administrative proceedings. Although the right to counsel is constitutionally protected by s. 10(b) the Charter, the protection of that right is limited to circumstances of "arrest or detention." In *British Columbia (Attorney General) v. Christie*, the Court noted that the right to counsel was understood historically as relevant only in the context of the criminal law, rather than something required by the rule of law itself, and concluded that there was no general constitutional right to counsel. The Court reasoned that such a right would render the specific protection afforded by the Charter redundant:

> We conclude that the text of the Constitution, the jurisprudence and the historical understanding of the rule of law do not foreclose the possibility that a right to counsel may be recognized in specific and varied situations. But at the same time, they do not support the conclusion that there is a general constitutional right to counsel in proceedings before courts and tribunals dealing with rights and obligations.[85]

In proceedings that are determined without an oral hearing, it is uncontroversial that a party may be represented by counsel—that is, there will be no cause for a decision-maker to refuse to deal with a party through his or her counsel. Representation by counsel is usual in the context of oral hearings, and the right to be represented by counsel is often set out in legislation. The right may extend beyond counsel to representation by a lay representative, depending on the nature of the proceedings and their sophistication.

At the same time, the right to counsel should not be understood in all or nothing terms. Even where there is a right to counsel, the right may be subject to limits. There will often be good reasons to limit the role of counsel in particular proceedings: although counsel may be of considerable benefit to the represented party, the involvement of counsel in administrative proceedings is likely to occasion additional cost, delay, and related problems for the administrative decision-maker, in addition to other parties to the proceedings.

Of course, it is one thing to have a right to be represented by counsel and another to be able to exercise that right: legal counsel is expensive, and as a practical matter may be beyond

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[84] See e.g. *Khan v. University of Ottawa* (1997), 34 O.R. (3d) 535 (C.A.), requiring that an oral hearing be held in the circumstances of an improbable factual claim made in the context of a grade appeal.

[85] 2007 SCC 21, [2007] 1 S.C.R. 873 at para. 27.

the reach of many in the administrative process. The Court acknowledged as much in rejecting the existence of a general right to counsel and considered cost to be a primary reason for denying the existence of such a constitutional right:

> This general right to be represented by a lawyer in a court or tribunal proceedings where legal rights or obligations are at stake is a broad right. It would cover almost all—if not all—cases that come before courts or tribunals where individuals are involved. Arguably, corporate rights and obligations would be included since corporations function as vehicles for individual interests. Moreover, it would cover not only actual court proceedings, but also related legal advice, services and disbursements. ... [T]he logical result would be a constitutionally mandated legal aid scheme for virtually all legal proceedings, except where the state could show this is not necessary for effective access to justice.[86]

The Court has held, however, that where a deprivation of life, liberty, or security of the person is at stake, the principles of fundamental justice may in some cases require the provision of counsel in the administrative process.[87]

5. Right to Call Evidence and Cross-Examine Witnesses

The right to call and cross-examine witnesses is normally part of the right to an oral hearing. The right is not absolute, however; administrative actors control their own procedures and may limit the exercise of the right.[88] The guiding principle is that parties must be afforded a reasonable opportunity to present their cases. In *Innisfil (Township) v. Vespra (Township)*, Justice Estey emphasized that the right of cross-examination is not to be withheld on the basis of a judgment by the tribunal that it is of limited utility: "The decision to exercise the right is solely that of the holder of the right. He, of course, must exercise it at his peril as is the case in any other administrative or judicial proceeding where such a right arises."[89]

6. Timeliness and Delay

Administrative decision-makers are not usually under specific statutory timelines for holding hearings or making decisions. Nor is there a Charter right to have an administrative matter heard or determined within a reasonable time—no equivalent to the right to a trial within a reasonable time (s. 11(b)), which applies only to persons charged with an *offence*.

It was inevitable that the question of delay would arise in the context of the administrative proceedings, for despite the relative advantages administrative tribunals are presumed

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86 *Ibid.* at para. 13.

87 *New Brunswick (Minister of Health and Community Services) v. G.(J.)*, [1999] 3 S.C.R. 46 (applicant at risk of losing custody of children in proceedings brought by the state).

88 This is reflected in procedural legislation such as Ontario's *Statutory Powers Procedure Act*, *supra* note 18, s. 3(2) and British Columbia's *Administrative Tribunals Act*, *supra* note 17, s. 38(2), both of which provide rights to cross-examination while permitting tribunals to limit examination and cross-examination to what they consider sufficient in the circumstances.

89 [1981] 2 S.C.R. 145 at 171.

to enjoy over courts—their ability to provide more efficient, less formal, and less expensive justice—administrative tribunal processes are often anything but speedy. It is not unusual for litigation before administrative tribunals to take longer than a criminal law prosecution involving the most serious offences. Many hearing days may be required to address a matter, and the need to balance the schedules of counsel and tribunal members—many of whom may be part-time members—can exacerbate the problem. Hearing days may be spread over many months and decisions may not be made for many months following the conclusion of a hearing.

Delay in the administrative process can have significant consequences, as the facts of *Blencoe v. British Columbia (Human Rights Commission)*[90] demonstrate. In that case, a former minister in a British Columbia government sought an order staying human rights tribunal proceedings in complaints against him, over 30 months after the date the complaints were filed. During that time his political career came to an end: he was dismissed from Cabinet, expelled from his caucus, and suffered from depression. The majority of the Supreme Court concluded that, in some circumstances, delay in the administrative process might rise to the level of a deprivation of liberty or security of the person under s. 7 of the Charter, which would violate the right if not in accordance with the principles of fundamental justice. In addition, the majority concluded that "undue" delay in an administrative proceeding might impair the fairness of a hearing, and could result in an abuse of process even if the fairness of a hearing were not compromised. However, the majority of the Court concluded that the delay did not infringe either s. 7 of the Charter or the duty of fairness in Blencoe's case.

The minority of the Court chose to deal with the matter solely on administrative law grounds and set out three considerations that had to be balanced in considering complaints of administrative delay:

> (1) *the time taken compared to the inherent time requirements* of the matter before the particular administrative body, which would encompass legal complexities (including the presence of any especially complex systemic issues) and factual complexities (including the need to gather large amounts of information or technical data), as well as reasonable periods of time for procedural safeguards that protect parties or the public;
>
> (2) *the causes of delay beyond the inherent time requirements of the matter*, which would include consideration of such elements as whether the affected individual contributed to or waived parts of the delay and whether the administrative body used as efficiently as possible those resources it had available; and
>
> (3) *the impact of the delay*, considered as encompassing both prejudice in an evidentiary sense and other harms to the lives of real people impacted by the ongoing delay. This may also include a consideration of the efforts by various parties to minimize negative impacts by providing information or interim solutions.[91]

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90 *Supra* note 28. See also the discussion of *Blencoe* by Evan Fox-Decent and Alexander Pless in Chapter 12, The Charter and Administrative Law: Cross-Fertilization or Inconstancy?

91 *Blencoe*, *supra* note 28 at para. 160 (italicized portions underlined in original).

The minority emphasized the importance of a contextual inquiry into the problem, eschewing the sorts of time limits or guidelines that caused so much difficulty in the context of the criminal law.[92] In the context of administrative proceedings, there were important interests, apart from those of persons complaining of delay, that had to be considered—in Blencoe's case, the interests of the women who complained of sexual harassment. The state was not Blencoe's antagonist, and staying the ability of the human rights tribunal to hold the hearing would deny the complainants their right to have their complaints heard. Thus, although they considered that the delay in Blencoe's case constituted an abuse of process, the minority of the Court considered that a stay of proceedings was inappropriate and would have made an order to expedite the proceedings instead.

Following *Blencoe*, it is clear that delay in providing a hearing—or, presumably, in rendering a decision[93]—may breach the duty of fairness and may even rise to the level of a Charter breach. But the normal remedy for delay is likely to be an order in the nature of mandamus, requiring the tribunal to perform its duty expeditiously.

7. The Duty to Give Reasons

Historically, there was no duty on administrative decision-makers to give reasons. That changed in *Baker*, when Justice L'Heureux-Dubé stated simply:

> In my opinion, it is now appropriate to recognize that, in certain circumstances, the duty of procedural fairness will require the provision of a written explanation for a decision. The strong arguments demonstrating the advantages of written reasons suggest that, in cases such as this where the decision has important significance for the individual, when there is a statutory right of appeal, or in other circumstances, some form of reasons should be required.[94]

The scope of the duty established in *Baker* is limited, at least in principle. Reasons are not required for all decisions; rather, they are required in "certain circumstances." L'Heureux-Dubé J. spelled out two such circumstances, and these reflect the dignitary and instrumental rationales that underlie the duty of fairness itself. Reasons are required if a particular decision has "important significance" for an individual, because public actors demonstrate respect for those affected by their decisions by justifying the decisions they make. Reasons are also required if a statutory appeal process exists to facilitate the workings of that process. It is difficult, if not impossible, to determine whether to appeal a particular decision and which sorts of arguments to make on appeal if no explanation is provided for that decision.

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92 The Charter right to trial within a reasonable time has given rise to the extreme remedy of having charges stayed, most controversially in *R. v. Askov*, [1990] 2 S.C.R. 1199, which resulted in tens of thousands of charges being stayed or withdrawn. The Court revisited the decision in *Askov* in *R. v. Morin*, [1992] 1 S.C.R. 771 and tightened things considerably.

93 For an Australian example, see *NAIS v. Minister for Immigration and Multicultural and Indigenous Affairs* (2005), 228 C.L.R. 470 (hearing spread over several years, culminating in a decision by the Refugee Review Tribunal five years following the commencement of the claim violates fairness). For a New Zealand example, see *Ngunguru Coastal Investments Ltd. v. Maori Land Court*, [2011] N.Z.A.R. 354 (three-year delay in rendering a reserve decision by land court violates fairness).

94 *Baker*, *supra* note 57 at para. 43.

Baker left open a potentially large residual discretion for courts to require reasons: reasons may be required in "other circumstances." Moreover, *Baker* contemplates flexibility in complying with the duty to give reasons. The requirement is to provide "some form of reasons" and, as a result, reasons may vary in length and formality in different circumstances. This reflects the wide variety of decision-makers covered by the duty and their relative abilities. Not all decisions are made by lawyers nor are they made on the basis of sophisticated submissions that help guide the decision-maker, and these considerations must be taken into account in determining the nature and scope of the duty to provide reasons. This is typified by the facts of *Baker* itself: the Court accepted that informal notes prepared by one immigration officer for the advice of another satisfied the duty.[95]

Two main concerns are likely to arise with regard to the duty to provide reasons. First, there may be a failure to provide reasons in circumstances in which a court concludes that reasons were required.[96] Second, questions may arise as to the adequacy of reasons proffered in particular circumstances, and it may be argued that inadequate reasons are tantamount to no reasons at all, and hence a violation of the duty.[97] As this argument suggests, there may be considerable overlap between the question *whether* reasons have been given and questions concerning the quality of reasons proffered in a particular case—the latter being a matter for substantive rather than procedural review.

The Court rejected a bifurcated approach to procedural and substantive questions about the duty to provide reasons in *Newfoundland and Labrador Nurses' Union v. Newfoundland and Labrador (Treasury Board)*.[98] The Court emphasized that reasons need not be provided in all cases and asserted that *Baker* does not establish that the quality of the reasons proffered in a particular case is a question of procedural fairness. On the contrary, as Justice Abella pointed out, the threshold for satisfying the requirement to provide reasons is very low:

> It strikes me as an unhelpful elaboration on *Baker* to suggest that alleged deficiencies or flaws in the reasons fall under the category of a breach of the duty of fairness and that they are subject to a correctness review. ... [If] there *are* reasons, there is no such breach. Any challenge to the reasoning/result of the decision should therefore be made within the reasonableness analysis.[99]

This seems clear enough, but Abella J. went on to endorse an observation made by David Dyzenhaus that the concept of deference to a decision requires "respectful attention to the

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95 The concession of counsel that these were in fact the reasons for the minister's decision facilitated the Court's decision—the notes were proffered in response to the request of Baker's counsel for reasons.

96 See e.g. *Congrégation des témoins de Jéhovah de St-Jérôme-Lafontaine v. Lafontaine (Village)*, 2004 SCC 48, [2004] 2 S.C.R. 650 at para. 13 (reasons for municipal council's refusal of rezoning application "serves the values of fair and transparent decision-making, reduces the chance of arbitrary or capricious decisions, and cultivates the confidence of citizens in public officials"). Cf. *Catalyst Paper Corp. v. North Cowichan (District)*, 2012 SCC 2 (reasons not required for passing municipal bylaws, as opposed to municipal decisions involving quasi-judicial adjudication).

97 See e.g. *Clifford v. Ontario Municipal Employees Retirement System* (2009), 312 D.L.R. (4th) 70 (Ont. C.A.); *Sussman v. College of Alberta Psychologists* (2010), 490 A.R. 304 (Alta. C.A.).

98 2011 SCC 62, [2011] 3 S.C.R. 708 [*Newfoundland Nurses' Union*].

99 *Ibid.*, at paras. 21-22. Remarkably, the Court did not discuss the conflicting authority in provincial appellate courts, *supra* note 97.

reasons offered *or which could be offered* in support of a decision."[100] Dyzenhaus was not concerned with cases in which no reasons were provided; he was addressing a situation in which the reasons provided were "in some respects *defective*."[101] It would be more apt to have said "deficient," for Dyzenhaus was concerned with the situation in which reasons were insufficient rather than problematic. This was the context in which he argued that a court could "supplement" the reasons for a decision.[102]

Given that one reason for deferring to the decisions of administrative actors is to respect the decision of the legislature to confer decision-making authority on them, the extent to which a generalist court can legitimately "supplement" the reasons for decisions they make is surely contestable. This is supported by the more limited reading the majority of the Court gives to the concept of "reasons which could be offered" in *Alberta (Information and Privacy Commissioner) v. Alberta Teachers' Association*.[103] In that case, Justice Rothstein described the concept as "apposite when the decision concerns an issue that was not raised before the decision maker," and emphasized that courts are not to reformulate a tribunal's reasons in order to render them reasonable.[104] On his account, the concept is useful mainly as a means of precluding the parties from misleading a tribunal by failing to raise a matter—in effect, causing the failure to provide reasons that is subsequently challenged on judicial review. Thus, Rothstein J.'s decision contemplates that it may sometimes be necessary to return a decision in order to allow a decision-maker to provide reasons on a particular matter, thereby allowing the Court to defer on an informed basis if the decision is reviewed subsequently.

All of this is to say that much requires clarification in future cases. At least this much is clear: a wholesale failure to provide reasons will constitute a breach of the duty of fairness. Following *Newfoundland Nurses' Union*, however, the Court will not be concerned with the adequacy or sufficiency of reasons in determining whether the duty to provide reasons has been met. The focus will be on the substantive question: do the reasons, such as they are,

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100 David Dyzenhaus, "The Politics of Deference: Judicial Review and Democracy" in Michael Taggart, ed., *The Province of Administrative Law* (Oxford: Hart, 1997) 279 at 286 [Dyzenhaus] (emphasis added). Dyzenhaus's observation was made prior to the establishment of a duty to give reasons in *Baker*, *supra* note 57, in the context of elaborating his "deference as respect" concept. Ironically, Dyzenhaus professed to being "undecided on the important topic of whether my argument entails the claim that there is a common law duty on tribunals to give reasons" (Dyzenhaus, *ibid.*, at n. 63), and went on to refer with apparent approval to the then common criticism that "a reason-giving requirement invites both judicial activism and distortion of the administrative process."

101 Dyzenhaus, *ibid.* at 304.

102 "[E]ven if the reasons in fact given do not seem wholly adequate to support the decision, the court must first seek to supplement them before it seeks to subvert them." Dyzenhaus, *ibid.*

103 2011 SCC 61, [2011] 3 S.C.R. 654. This case was released one day prior to the decision in *Newfoundland Nurses' Union*, *supra* note 98, but is not mentioned in that judgment.

104 Justice Rothstein refers with approval to *Petro-Canada v. British Columbia (Workers' Compensation Board)*, 2009 BCCA 396 at paras. 53, 56, where the Court stated that respectful attention to the reasons "which could be offered in support of a decision" is not "carte blanche to reformulate a tribunal's decision in a way that casts aside an unreasonable chain of analysis in favour of the court's own rationale for the result."

"allow the reviewing court to understand why the tribunal made its decision and permit it to determine whether the conclusion is within the range of acceptable outcomes"?[105]

VI. Judicial Review of the Duty of Fairness

It is well established that the requirements of the duty of fairness are independent of the merits of the substantive matter in issue and that breach of the duty voids a decision. The Supreme Court of Canada expressed the point categorically in *Cardinal*:

> [T]he denial of a right to a fair hearing must always render a decision invalid, whether or not it may appear to a reviewing court that the hearing would likely have resulted in a different decision. The right to a fair hearing must be regarded as an independent, unqualified right which finds its essential justification in the sense of procedural justice which any person affected by an administrative decision is entitled to have. It is not for a court to deny that right and sense of justice on the basis of speculation as to what the result might have been had there been a hearing.[106]

This statement of the law finds considerable support in English law and its rationale is best set out in the oft-quoted remarks of Justice Megarry:

> It may be that there are some who would decry the importance which the courts attach to the observance of the rules of natural justice. "When something is obvious," they may say, "why force everybody to go through the tiresome waste of time involved in framing charges and giving an opportunity to be heard? The result is obvious from the start." Those who take this view do not, I think, do themselves justice. As everybody who has anything to do with the law well knows, the path of the law is strewn with examples of open and shut cases which, somehow, were not; of unanswerable charges which, in the event, were completely answered; of inexplicable conduct which was fully explained; of fixed and unalterable determinations that, by discussion, suffered a change. Nor are those with any knowledge of human nature who pause to think for a moment likely to underestimate the feelings of resentment of those who find that a decision against them has been made without their being afforded any opportunity to influence the course of events.[107]

However, in *Mobil Oil Canada Ltd. v. Canada-Newfoundland Offshore Petroleum Board*,[108] the Court endorsed the view expressed by Sir William Wade that "[a] distinction might perhaps be made according to the nature of the decision. In the case of a tribunal which must decide according to law, it may be justifiable to disregard a breach of natural justice where the demerits of the claim are such that it would in any case be hopeless."[109] The

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105 The concept of reasonableness is addressed by Sheila Wildeman in Chapter 10, Pas de Deux: Deference and Non-Deference in Action.

106 *Cardinal*, *supra* note 10 at para. 23.

107 *John v. Rees*, [1970] Ch. 345 at 402.

108 [1994] 1 S.C.R. 202 [*Mobil Oil*].

109 William Wade, *Administrative Law*, 6th ed. (Oxford: Oxford University Press, 1988) at 535. This is repeated in H.W.R. Wade & C.F. Forsyth, *Administrative Law*, 10th ed. (Oxford: Oxford University Press, 2009) at 424.

Court refused to quash a decision in the face of a breach of procedural fairness in *Mobil Oil*, but did so on the basis that it would be "impractical" and "nonsensical" to do so, because, as a result of a cross-appeal, the tribunal would have no alternative but to reject the application in question. The Court described these circumstances as "exceptional," and reiterated that it "would not wish to apply it [the exception] broadly." Thus, *Cardinal* remains good law and the *Mobil Oil* exception should be rare.[110]

It is important to emphasize that although judicial review is concerned with deciding what the duty of fairness requires in the circumstances of a particular decision, the reviewing court's decision is made *after* the decision is made, and is made in the knowledge that a finding that the duty of fairness was breached will result in the relevant decision being quashed.

The retrospective nature of fairness determinations brings to mind Jeremy Bentham's complaint about the common law.[111] The problem is mitigated by the sort of institutional knowledge that builds up over time. Still, there may be a tendency for risk-averse administrators to provide more than the duty of fairness might otherwise be held to require in order to ensure that their decisions can withstand judicial review.

Judicial review of a decision on procedural grounds must be differentiated from judicial review on substantive grounds. The Supreme Court of Canada subjects substantive decisions to review on either a correctness or a reasonableness standard, pursuant to which the Court may defer to the decisions of an administrative agency.[112] No similar approach is taken with regard to the duty of fairness. Historically, compliance with the duty of fairness has been regarded as a jurisdictional question and, as such, a question that must be answered correctly. If it is not, then jurisdiction will be lost, the relevant decision will be quashed, and the decision-maker will be required to make a fresh decision in accordance with the correct procedure.

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110 Nevertheless, some courts appear to have assumed the existence of a broader discretion to refuse to quash a decision where the duty of fairness has been breached. In *Veillette v. International Association of Machinists and Aerospace Workers*, 2011 FCA 32 at para. 16, the Federal Court of Appeal put the point this way: "Even a breach of the principles of natural justice or procedural fairness does not automatically invalidate the decision." In addition to *Mobil Oil*, *supra* note 108, the Court cited *Canada (Minister of Human Resources Development) v. Hogervorst*, 2007 FCA 41; *Halifax Employers Ass. Inc. v. Council of ILA Locals for the Port of Halifax*, 2006 FCA 82; *Société des arrimeurs de Québec v. Canadian Union of Public Employees, Local 3810*, 2008 FCA 237; *Palonek v. Canada (Minister of National Revenue—M.N.R.)*, 2007 FCA 281; and *Cartier v. Canada (Attorney General)*, 2002 FCA 384. Cf. *Persaud v. Canada (Citizenship and Immigration)*, 2011 FC 31 at para. 19, in which Justice Hughes of the trial division reads the *Mobil Oil* exception much more narrowly: "The point being made by the Supreme Court is that where a breach of natural justice or procedural fairness has been found the Court cannot refuse to send it back because it supposes that the case would be found to be futile. A rare exception exists where the remedy sought would not be relevant in the context of the matter presently before the Court."

111 Jeremy Bentham, *The Works of Jeremy Bentham*, ed. by John Bowring, vol. 5 (Edinburgh: W. Tait, 1843) at 235: "It is the judges (as we have seen) that make the common law. Do you know how they make it? Just as a man makes laws for his dog. When your dog does anything you want to break him of, you wait till he does it, and then beat him for it. This is the way you make laws for your dog: and this is the way the judges make law for you and me." (First published in 1792 as "Truth Versus Ashurst; or, Law as It Is, Contrasted with what It Is Said to Be.")

112 *Dunsmuir*, *supra* note 9.

As we have seen, there is some room for deference when it comes to determining the content of the duty of fairness, because the procedural choices made by the decision-maker are one of the considerations courts must take into account. However, once the content of the duty in a particular context has been determined, the question for the court is simply whether the duty of fairness has been met on the facts of the case—a question that will yield a yes or no answer.

Violation of the duty of fairness will not result in the imposition of a substantive outcome by the court. The role of the court is to supervise the decision-making *process*—to ensure that the relevant decision has been made properly, not that the "proper" decision has been made. Although a successful application for judicial review on fairness grounds will result in an order quashing a decision and requiring it to be made anew, nothing necessarily prevents the decision-maker from reaching the same substantive decision. Nevertheless, as *Baker* demonstrates, a new hearing may well lead to a different outcome. Mavis Baker was subsequently granted the humanitarian and compassionate exception she sought and was allowed to stay in Canada.

Whether or not a different result obtains on a rehearing, the consequences of a breach of the duty of fairness may be significant. Administrative proceedings can take months—even years—and be hugely expensive for all those involved.[113] An order quashing a decision may cause great inconvenience not only to those involved but also to the public interest, by requiring that proceedings be repeated, with all the associated cost and delay. Strict adherence to the automatic quashing remedy may result in problems from time to time. Moreover, the automatic nature of the remedy may turn out to be counterproductive to the protection of the right. It is possible that, in close cases, courts might err on the side of finding that the duty has been met, given the far-reaching consequences an order quashing a particular decision may have. As long as quashing is the usual remedy for a breach of fairness, courts may be circumspect in expanding the scope and content of the duty of fairness.

SUGGESTED ADDITIONAL READINGS

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113 See e.g. *Canada (Attorney General) v. Canada (Commission of Inquiry on the Blood System)*, *supra* note 29 (judicial review of commission of inquiry [the Krever commission] that held hearings over a two-year period).

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Wells v. Newfoundland, [1999] 3 S.C.R. 199.

SCHEDULE "B"

TEXT OF STATUTES, REGULATIONS & BY – LAWS

1. *Electricity Act, 1998*, SO 1998, c 15, Sch A, as amended.

2. *Ontario Energy Board Act, 1998*, SO 1998, c 15, Sch B, as amended.

3. *Ontario Energy Board By-Law 2 "Market Surveillance Panel"*, as amended.

4. OEB and IESO, "Protocol" dated April 25, 2005", as amended.

SCHEDULE "C"

SELECT MARKET RULES

1. "Chapter 3 of the IESO Market Rules issued May 1, 2023:

S 2.2.1.1 "any dispute between the *IESO* and any *market participant* which arises under the *market rules, market manuals* or any standard, policy or procedure established by the *IESO* pursuant to these *market rules,* including with respect to any alleged violation or breach thereof, whether or not specifically identified in the *market rules* as a dispute to which this section 2 applies.

. . . . . .

S 2.7.25 "Where, in the case of a dispute referred to in section 2.2.1.1 the *arbitrator* concludes that the *IESO* has violated, misinterpreted or misapplied a *market rule,* the *arbitrator* may, subject to section 13 of Chapter 1 and to any other provision of these *market rules* pertaining specifically to liability, assess such damages or make such further and other orders or directions as the *arbitrator* considers just and reasonable. Without limiting the generality of the foregoing, where the *arbitrator* determines that the breach, misinterpretation or misapplication of a *market rule* by the *IESO* was intentional or could have been avoided by the exercise of due diligence by the *IESO,* the *arbitrator* shall direct the *IESO* to comply with the *market rules* or to interpret or apply the *market rules* in a particular manner. Any such direction may be included in the summary referred to in section 2.9.2.4"

. . . . . .

S 2.7.32 "Subject to section 2.7.32A, the *arbitrator* may make such award as to costs as he or she determines just and reasonable provided that, except in exceptional cases:

2.7.32.1 where in the context of a dispute referred to in section 2.2.1 the award consists of damages for breach of the *market rules,* costs, including the *costs of the arbitration,* shall be awarded to the successful party;

2.7.32.2 where the award consists of the imposition of penalties on a *market participant,* costs, including the *costs of the arbitration,* shall be awarded to the *IESO;* and

2.7.32.3 where the award consists of the direction to the *IESO* to comply with the *market rules* or to interpret or apply a *market rule* in a particular manner pursuant to section 2.7.25, costs, including the *costs of the arbitration,* shall be awarded to the *market participant* seeking the direction."

. . . . . .

S 6.2.1 "This section shall not apply to the issuance by the *IESO* of a *suspension order* or *termination order,* which shall be governed by the provisions of section 6.3A or 6.4, respectively, or to the issuance by the *IESO* of an order referred to in section 6.2A.1, which shall be governed by the applicable provisions of section 6.2A and 6.5."

. . . . . .

S 6.2.4 "Following expiry of the time noted in section 6.2.3.4, and after consideration of any representations made by the *market participant* pursuant to that section, the *IESO* may:

6.2.4.1 determine that the *market participant* has not breached the *market rules;*

6.2.4.2 subject to section 6.2.5, determine that the *market participant* is in breach of the *market rules;*

6.2.4.3 request that the *market participant* provide further information in relation to the alleged breach; or

6.2.4.4 conduct such further investigation into the matter as the *IESO* determines appropriate."

S 6.2.5 "Where a *market participant* has requested a meeting pursuant to section 6.2.3.5, the *IESO* shall provide the *market participant* with a reasonable opportunity to meet with the *IESO* to discuss the allegations. In such case, the *IESO* shall not make the determination noted in section 6.2.4.2 until such reasonable opportunity has been given."

. . . . . .

S 6.2.7 "Subject to section 6.2.7A, where the *IESO* determines that a *market participant* has breached the *market rules,* the *IESO* may by order do any one or more of the following:

6.2.7.1 direct the *market participant* to do, within a specified period, such things as may be necessary to comply with the *market rules;*

6.2.7.2 direct the *market participant* to cease, within a specified period, the act, activity or practice constituting the breach;

6.2.7.3 impose additional or more stringent record-keeping or reporting requirements on the *market participant;*

6.2.7.4 issue a non-compliance letter in accordance with section 6.6;

6.2.7.5 impose financial penalties in accordance with section 6.6 indicating the time within which payment of the financial penalty must be made to the *IESO,* provided that no such penalties shall be imposed unless the *IESO* is satisfied that the breach could have been avoided by the exercise of due diligence by the *market participant* or that the *market participant* acted intentionally; or

6.2.7.6 take such other action as may be provided for in Appendix 3.1 in respect of the *market rule* that has been breached by the *market participant*".

. . . . . .

S 6.6.2 "Where the *IESO* has determined that it is appropriate to issue a letter of non-compliance or impose a financial penalty upon a *market participant,* the *IESO* shall:

6.6.2.1 determine the level of non-compliance by the *market participant* in accordance with section 6.6.3;

6.6.2.2 determine the rate of recurrence of non-compliance by the *market participant* in accordance with section 6.6.4;

6.6.2.3 based on the determinations made in accordance with sections 6.6.2.1 and 6.6.2.2, issue a non-compliance letter or impose a financial penalty; and

6.6.2.4 where a determination is made to impose a financial penalty, fix the amount of the penalty in accordance with section 6.6.6."

. . . . . .

S 6.6.10A "In respect of a breach of section 7.5.8A of Chapter 7, the *IESO* may:

6.6.10A.1 issue a letter of non-compliance or impose a financial penalty upon the *market participant* pursuant to sections 6.6.2.3, and 6.6.6; and

6.6.10A.2 adjust *settlement amounts* paid or payable to a *registered market participant* such as *transmission rights* payments, congestion management *settlement* credits or other *settlement amounts* that the *registered market participant* received or avoided due to an act or omission or a course of conduct of either the *registered market participant* alone or the *registered market participant* by agreement or arrangement with one or more other *market participants* that led to the breach of section 7.5.8A of Chapter 7."

2. Chapter 7 of the IESO Market Rules issued November 29, 2023":

S 7.5.8A "A *registered market participant* associated with a *registered facility* that is a *boundary entity* shall, other than for the bona fide and legitimate reasons referred to in section 7.5.8B, schedule *energy* and *operating reserve,* in accordance with section 6.1.3, with the appropriate scheduling entity, or scheduling entities as the case may be."

S 7.5.8B " The *IESO* may take actions pursuant to section 6.6.10A of Chapter 3 and shall assess a real-time import or export failure charge as determined in section 3.8C of Chapter 9 where a *registered market participant* associated with a *registered facility* that is a *boundary entity* fails to schedule *energy* or *operating reserve,* in accordance with section 6.1.3 of Chapter 7, with the appropriate scheduling entity, or scheduling entities as the case may be, according to the applicable *interchange schedule,* other than for bona fide and legitimate reasons as determined by the *IESO.* Bona fide and legitimate reasons shall include failures caused by actions and circumstances beyond the control of the *market participant* or due to *IESO* or external scheduling entity error or action, including those reasons specified in the applicable *market manual."*

3. Chapter 9 of the IESO Market Rules issued November 29, 2023:

S 3.1.3 "The *IESO* shall determine *energy market* prices and quantities as provided in Chapter 7 and shall provide the following variables and data from the *energy market,* determined in accordance with section 3.1.4A, directly to the *settlement process:*

$$CRF_h = \Sigma_{t,m} (EMP_h^{m,t} - EMP_h^{REF,t}) \times \Sigma_k (AQEW_{k,h}^{m,t} - AQEI_{k,h}^{m,t}) - \Sigma_k TRSC_{k,h}$$

where:

t = all *metering intervals* in *settlement hour* 'h'
m = all *primary* RWMs and *intertie metering points*
k = all *market participants*

EMPhREF,t= energy market price at the reference bus in metering interval 't' of settlement hour 'h'. Until such time that locational pricing is implemented in the IESO-administered markets, the uniform energy market price is the energy market price at the reference bus".

. . . . . .

S 3.5 "Hourly Settlement Amounts for Congestion Management"

3.5.2 Subject to sections 3.5.1A, 3.5.1D, 3.5.1E, 3.5.1F, 3.5.1G, 3.5.6, 3.5.6A, 3.5.6B, 3.5.6C, 3.5.6D, 3.5.6F, 3.5.6G, 3.5.9, 3.5.10 and 3.5.11 and subject to Appendix

7.6 of Chapter 7, the hourly congestion management *settlement* credit for *market participant* 'k' for *settlement hour* 'h' ("$CMSC_{k,h}$") shall be determined by the following equation:

Let 'BE' be a matrix of n *price-quantity pairs* offered by *market participant* 'k' to supply *energy* during *settlement hour* 'h'

Let 'BR_r' be a matrix of n *price-quantity pairs* offered by *market participant* 'k' to supply class r *operating reserve* during *settlement hour* 'h'

Let 'BL' be a matrix of n *price-quantity pairs* bid by *market participant* 'k' to withdraw *energy* by a *dispatchable load* or an *electricity storage facility* during *settlement hour* 'h'

Let OP(P,Q,B) be a profit function of Price (P), Quantity (Q) and an n x 2 matrix (B) of offered *price-quantity pairs*:

$$OP(P,Q,B) = P \cdot Q - \sum_{i=1}^{s^*} P_i \cdot (Q_i - Q_{i-1}) - (Q - Q_{s^*}) \cdot P_{s^*+1}$$

Where:
s^* is the highest indexed row of B such that $Q_{s^*} \le Q \le Q_n$ and where, $Q_0=0$
B is matrix BE, BR_r, or BL (see above)

Using the terms below, let CMSC be expressed as follows:

$CMSC_{k,h} = OPE_{k,h} - OPR_{k,h} + OPL_{k,h}$

Where:

$OPE_{k,h}$ represents that component of the congestion management *settlement* credit for *market participant* 'k' during *settlement hour* 'h' attributable to a constraint on *energy* production subject to section 3.5.1 and is calculated as follows:

$$OPE_{k,h} = \sum_{m,t} \left[\begin{array}{l} OP(EMP_h^{m,t}, MQSI_{k,h}^{m,t}, BE) - \\ MAX\left(OP(EMP_h^{m,t}, DQSI_{k,h}^{m,t}, BE), OP(EMP_h^{m,t}, AQEI_{k,h}^{m,t}, BE)\right) \end{array} \right]$$

Where:

MAX[X,Y] = Maximum of X or Y

During any *metering interval* 't' within *settlement hour* 'h' in which the mathematical sign of $DQSI_{k,h}^{m,t} - MQSI_{k,h}^{m,t}$ is not equal to the mathematical sign

of $AQEI_{k,h}^{m,t} - MQSI_{k,h}^{m,t}$, the component of $OPE_{k,h}$ at location m, determined in accordance with section 3.1.4A, or *intertie metering point* 'm' for that *metering interval* 't' shall equal zero.

$OPR_{k,h}$ represents that component of the congestion management *settlement* credit for *market participant* 'k' during *settlement hour* 'h' attributable to a constraint on the provision of *operating reserve* subject to section 3.5.1 and is calculated as follows:

$$OPR_{k,h} = \sum_{m,t,r} \left[\begin{array}{l} OP(PROR_{r,h}^{m,t}, SQROR_{r,k,h}^{m,t}, BR_r) - \\ MAX\left(OP(PROR_{r,h}^{m,t}, DQSR_{r,k,h}^{m,t}, BR_r), OP(PROR_{r,h}^{m,t}, AQOR_{r,k,h}^{m,t}, BR_r)\right) \end{array} \right]$$

During any *metering interval* 't' within *settlement hour* 'h' in which the mathematical sign of $DQSR_{r,k,h}^{m,t} - SQROR_{r,k,h}^{m,t}$ is not equal to the mathematical sign of $AQOR_{r,k,h}^{m,t} - SQROR_{r,k,h}^{m,t}$, the component of $OPR_{k,h}$ at location m, determined in accordance with section 3.1.4A, or *intertie metering point* 'm' for that *metering interval* 't' shall equal zero.

$OPL_{k,h}$ represents that component of the congestion management *settlement* credit for *market participant* 'k' during *settlement hour* 'h' attributable to a constraint on the withdrawal of *energy* by a *dispatchable load* or an *electricity storage facility* subject to section 3.5.1. $OPL_{k,h}$ utilizes the negative of each output from each component Operating Profit (OP) function so as to correct for negative revenue streams (owing to withdrawals of *energy*).

$OPL_{k,h}$ is calculated as follows:

$$OPL_{k,h} = \sum_{m,t} \left[\begin{array}{l} -1 \times OP(EMP_h^{m,t}, MQSW_{k,h}^{m,t}, BL) - \\ MAX\left(-1 \times OP(EMP_h^{m,t}, DQSW_{k,h}^{m,t}, BL), -1 \times OP(EMP_h^{m,t}, AQEW_{k,h}^{m,t}, BL)\right) \end{array} \right]$$

During any *metering interval* 't' within *settlement hour* 'h' in which the mathematical sign of $DQSW_{k,h}^{m,t} - MQSW_{k,h}^{m,t}$ is not equal to the mathematical sign of $AQEW_{k,h}^{m,t} - MQSW_{k,h}^{m,t}$, the component of $OPL_{k,h}$ at location m, determined in accordance with section 3.1.4A, or *intertie metering point* 'm' for that *metering interval* 't' shall equal zero.

S 3.6 "Hourly Settlement Amounts for Transmission Rights and s"

3.6.1 The *TR settlement* credit for *market participant* 'k' in *settlement hour* 'h' ("$TRSC_{k,h}$") shall, other than where section 4.4.2.2 of Chapter 8 applies, be determined by the following equation:

$TRSC_{k,h} = \max[0, \sum_j (1/12) \times QTR_{k,h}^{j} \times \sum_t (EMP_h^{j,t} - EMP_h^{i,t})]$

where:

j = all *primary RWM's* and *intertie metering points*

i = all *primary RWM's* and *intertie metering points*

3.6.2 The contribution to the *transmission charge reduction fund* in *settlement hour* 'h' ("$TCRF_h$") shall be the net congestion rentals collected by the *IESO* (the negative of the net *energy market settlement* credit paid to *market participants*) less the net payments from the *IESO* to *market participants* under *TRs*, or:

$$TCRF_h = \sum_{t,m} (EMP_h^{m,t} - EMP_h^{REF,t}) \times \sum_k (AQEW_{k,h}^{m,t} - AQEI_{k,h}^{m,t}) - \sum_k TRSC_{k,h}$$

where:

t = all *metering intervals* in *settlement hour* 'h'

m = all *primary* RWMs and *intertie metering points*

k = all *market participants*

$EMP_h^{REF,t}$ = *energy market price* at the reference bus in metering interval 't' of *settlement hour* 'h'. Until such time that locational pricing is implemented in the *IESO-administered markets*, the uniform *energy market price* is the *energy market price* at the reference bus.

3.6.3 Disbursements from the *TR clearing account* authorised by the *IESO Board* pursuant to section 4.18.2 of Chapter 8 shall be used by the *IESO* in accordance with section 4.7.

3.6.4 Any net revenues received from the sale of a *TR* in a *TR auction*, along with the hourly balance accrued in the *transmission charge reduction fund*, shall be credited to the *TR clearing account* and shall be used in accordance with the provisions of section 3.6.3 and of Chapter 8.

4. Chapter 11 of the IESO Market Rules issued November 29, 2023 (select definitions):

    - *intertie congestion price (ICP)* means, in respect of a given dispatch hour, a price equal to the projected market price for energy or operating reserve for a given intertie zone minus the projected uniform market price for energy or operating reserve respectively, in the IESO control area, determined in accordance with section 8.1.1A of Chapter 7;

    - *settlement amount* means any amount of money to be paid by or to a *market participant,* determined in accordance with Chapter 9;

NEXUS ENERGY INC. -and- INDEPENDENT ELECTRICITY SYSTEM OPERATOR (IESO)

Applicant Respondent

IN THE MATTER OF an Arbitration under Chapter 3 of the IESO Market Rules made pursuant to section 32 of the Ontario *Electricity Act, 1998*, S.O. 1998, c. 15, as amended

MEMORIAL OF THE APPLICANT, NEXUS ENERGY INC.

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Lawyers for the Applicant

TAB 2

IN THE MATTER OF an Arbitration under Chapter 3 of the IESO Market Rules made pursuant to section 32 of the Ontario *Electricity Act, 1998*, S.O. 1998, c. 15, as amended

B E T W E E N:

NEXUS ENERGY INC.

Applicant

- and -

INDEPENDENT ELECTRICITY SYSTEM OPERATOR (IESO)

Respondent

AFFIDAVIT OF ROBIN DOOLITTLE

(AFFIRMED OCTOBER 29, 2025)

I, Robin Doolittle, of the City of Toronto, in the Province of Ontario, AFFIRM:

1. I am the Managing Director, Trading & Marketing for Nexus Energy Inc. ("**Nexus Energy**"), the applicant in this dispute and as such have direct knowledge of the matters contained in this affidavit unless otherwise specified.

2. I have been employed in the energy trading industry for over 20 years. Prior to joining Nexus Energy in October 2018, I worked as a Logistics Coordinator and Market Operations Coordinator at Ontario Power Generation and subsequently as a Real Time Power Trader, Vice President of Power Trading and Director of Power Trading at the Royal Bank of Canada, in both cases involved in energy trading and market analytics. A copy of my curriculum vitae is attached to this affidavit as **Exhibit "A"**.

Nexus Energy

3. Nexus Energy is a privately held company with its head office in Toronto, Ontario.

4. Nexus Energy signed a participation agreement with the IESO on August 16, 2017. A copy of that participation agreement is attached to this affidavit as **Exhibit "B"**.

5. Since registering as a market participant with the IESO in 2017, Nexus Energy has steadily grown from approximately 3 employees to about 32 employees, including a team of 10 energy traders whom I currently oversee.

6. Generally speaking, Nexus Energy performs dozens of energy market transactions per day. According to the Notice of Non-Compliance, the 1,658 transactions at issue in this arbitration (the "**Subject Transactions**") represent a small percentage of the energy trading transactions performed by Nexus Energy through the IESO between December 2017 and December 2023. In my view, this level of transaction failure in the energy trading industry is part of the ordinary course of business.

7. In addition to trading energy in Ontario (through the IESO market), my team participates in other North American energy trading markets, including: the New York Independent System Operator ("**NYISO**"); the Midcontinent Independent System Operator ("**MISO**") (covering 15 U.S. states and Manitoba); the Pennsylvania Jersey Maryland Interconnection ("**PJM**"); and ISO New England ("**ISO-NE**").

8. The following section provides a high-level description of how my team participates in those interjurisdictional energy trading markets.

Intertie energy trading

9. An intertie (or "inter-tie") refers to the transmission line connecting two or more separate power systems (e.g. Ontario and New York). Intertie energy trading refers to the trade in electricity flows between those separate power systems. This allows for the balancing of supply and demand in both systems, which helps to maintain power grid stability and reliability, especially during periods of peak demand and expected shortages.

10. More specifically in this case, intertie energy trading is the trade in electricity flows between certain North American jurisdictions (such as the IESO market in Ontario and the NYISO market in New York). These intertie transactions consist of imports of electricity from another jurisdiction into Ontario, exports of electricity from Ontario to a neighbouring jurisdiction, or so-called "wheel-throughs" where electricity is moved *through* a jurisdiction by scheduling an import on one intertie and a corresponding export on another intertie.

11. To schedule an energy import into (or an export out of) Ontario, an energy trader like Nexus Energy must submit an electronic offer to the IESO to sell electricity to Ontario (or submit an electronic bid to the IESO to buy electricity from Ontario). Broadly speaking, an energy import or export will be accepted by the IESO and scheduled if it is economic (in comparison to other electricity supply or demand) and the transmission grid and the transmission line (intertie) can physically accommodate the transaction.

12. Energy trading transactions are often scheduled in the “pre-dispatch” timeframe, i.e. in the two hours preceding the “real-time” hour during which the energy is to be imported or exported through the applicable intertie (transmission line(s)).

13. To ensure that an intertie transaction scheduled with the IESO is able to flow in real-time, my team of energy traders also must at the same time take steps in the neighbouring jurisdiction such as obtaining a parallel instruction (aka “schedule”) to import or export, and/or obtaining ramp and transmission line capacity.

14. The manner in which a market participant may obtain a schedule from another jurisdiction varies, depending on the particular market design. Some electricity system operators (such as NYISO in the New York market) schedule transactions based primarily on whether a market participant’s offer to sell electricity to, or buy electricity from, New York is economic and the market participant is not required to purchase or reserve space (aka “capacity”) on the intertie transmission line in advance. In other electricity trading markets (such as MISO), the market participant must separately book and reserve capacity on the intertie transmission line to be in a position to flow the transaction.

15. The timelines in which these steps must be taken in Ontario and the neighbouring jurisdiction during the pre-dispatch period do not always perfectly line up. These are sometimes called “seams” issues (that is, issues with scheduling along the “seams” joining the import or export from one jurisdiction with the corresponding export or import in the other jurisdiction). This sometimes results in intertie transactions – including those scheduled by the IESO – to fail in real-time, through no fault of any market participant.

16. For example, for electricity trading between Ontario and New York, Nexus Energy must submit its import/export offer/bid to NYISO roughly 30 minutes ***before*** it learns whether it has a binding schedule with the IESO. If its offer/bid is not accepted by NYISO, the transaction already scheduled in Ontario by the IESO will "fail". In that case, no transaction occurs and there is no actual flow of electricity nor receipt of market revenues by Nexus Energy.

17. In the Subject Transactions at issue in this arbitration, there was no actual flow of electricity and therefore no transaction was completed, whether for "seams issues" or otherwise. (The exception is that for some of the Subject Transactions, a portion of the volume of the electricity associated with the original scheduled transaction did flow, meaning that it was only a partially failed transaction.)

IESO coding of intertie transactions

18. As part of administering the intertie energy trading market in Ontario, the IESO's electronic systems apply an automated code to each scheduled transaction. Which code the IESO applies can depend on if the transaction was completed or failed, and if it failed, for what reason.

19. Intertie transactions can fail for reasons which the IESO treats to be "outside a participant's control" – in other words, the transaction failed "for bona fide and legitimate reasons". These include, for example, an import or export transaction being cancelled by a system operator (e.g. IESO, MISO, NYISO, etc.) due to transmission grid constraints, transmission grid security or for reasons relating to the safety of equipment or persons.

20. Failed transactions in this "bona fide" category are assigned codes such as "TLRe" (i.e. "External ISO[1] Curtailments" for transactions that are cancelled or "curtailed" for system adequacy or security reasons).

21. One of the available codes which is assigned to certain other categories of failed transactions, is "OTH" (or "other"). The "OTH" code means the transaction failed not for bona fide or legitimate reasons (according to the IESO). The Subject Transactions were all coded "OTH" by the IESO.

IESO Notice of Non-Compliance and Order against Nexus

22. On April 4, 2024, Nexus Energy received the Notice of Alleged Breach for the Subject Transactions. A copy of the Notice of Alleged Breach is attached to this affidavit as **Exhibit "C"**.

23. The Notice of Alleged Breach was a surprise to me and my colleagues at Nexus Energy. I was surprised to read that the IESO could seek payment for something called "avoided congestion rents". While I was aware of congestion rents (sometimes also referred to as the intertie congestion price ("**ICP**")), I was not aware of a separate charge called "avoided" congestion rents as a settlement adjustment.

24. To my knowledge, following the implementation of automated import failure charges ("**IFCs**") and export failure charges ("**EFCs**") in 2006, as described further below, there was no publicly reported compliance or enforcement action taken by MACD for

[1] Electricity system operators in the U.S. are commonly referred to in the energy industry as Independent System Operators ("**ISOs**") or Regional Transmission Operators ("**RTO**s").

almost 14 years (2006 to 2019) against any market participants with respect to intertie transaction failures.

25. Based on the IESO's website it appears that in 2019 MACD began taking compliance and enforcement action against market participants for failed intertie transactions. A printout of the IESO webpage entitled "Sanctions" for 2020, and a printout of the IESO webpage entitled "Negotiated Settlements" for 2019 to 2021, are attached together as **Exhibit "D"**.

26. Based on these IESO webpages, there have been only three previous enforcement actions (one in each of 2019, 2020 and 2021) for failed intertie transactions. Nowhere on these IESO webpages, nor on the IESO's "Compliance Enforcement" webpages generally, have I seen that adjusted settlement amounts for failed intertie transactions include "avoided congestion rents". A printout of the IESO webpage where MACD publishes its "Issued Compliance and Enforcement Guidance" is attached as **Exhibit "E"**.

27. Because of the implementation of automated IFCs and EFCs in 2006, I had inferred that the summaries for failed intertie transactions (described as breaches of Chapter 7, section 7.5.8A of the Market Rules on the IESO's Sanctions and Negotiated Settlements webpages) pertained to the recovery of transmission rights payments and/or some form of nefarious behaviour such as intentional market manipulation.

28. To my knowledge, at no time prior to this dispute did the IESO publish any document or information to advise market participants of its interpretation that "avoided

congestion rents" could be sought by way of a settlement adjustment under Chapter 3, section 6.6.10A of the Market Rules.

29. If the IESO had the authority to seek "avoided congestion rents" for failed intertie transactions, I would have expected MACD to advise market participants accordingly by, for example, publishing such information on the IESO's website. To my knowledge, IESO/MACD never did this.

30. On December 17, 2024, Nexus Energy received the Notice of Non-Compliance with covering letter from MACD. The cover letter states that Nexus Energy is required to pay to the IESO $2,078,824.92 "in congestion rents avoided by NEXUS due to breaches regarding 1,658 transaction failures identified in the [Notice of Alleged Breach]". This is the dollar amount at issue in this arbitration. A copy of the Notice of Non-Compliance is attached as **Exhibit "F"**.

31. The letter also states that Nexus Energy is required to pay $4,931.76 in transmission rights benefits. Based on my inference from the above-mentioned IESO webpage summaries that the recovery in those instances was related to transmission rights payments, we typically refrained from bidding on transmission rights for interties where we frequently experienced failures due to seams issues, even though doing so meant foregoing potential additional revenues. Accordingly, the $4,91.76 in transmission rights payments (like the over $1,663,000 that Nexus Energy has paid in IFCs and EFCs – including for many of the Subject Transactions) are not being challenged in this arbitration.

32. In contrast to the transmission rights payments, MACD's charge of $2,078,824.92 for "avoided congestion rents" was payment out-of-pocket by Nexus Energy for transactions that never happened. It was not a claw-back of any revenues or benefits ever received by Nexus Energy. To the contrary, because the Subject Transactions never happened, Nexus also missed out on the potential revenues from those trades. A copy of the IESO invoice dated February 14, 2025 which includes the debit of $2,078,824.92 from Nexus Energy under charge type numbers 1111 and 1113, is attached as **Exhibit "G"**.

33. Prior to this dispute, and based on the abovementioned IESO/MACD webpages, it was my understanding that any settlement adjustment for failed intertie transactions (i.e. a breach of Chapter 7, section 7.5.8A of the Market Rules) would be limited to associated monies actually received and only where the market participant is found to have engaged in market manipulation like behaviour.

34. Moreover, ICPs are collected only on *actual* flows and are credited to the IESO's Transmission Rights Clearing Account ("**TRCA**"). My understanding is that the TRCA is designed by the IESO to offset transmission rights payouts to transmission rights holders, with any surplus being disbursed to market participants.

35. While the TRCA has had shortfalls in the past, I do not believe any shortfall occurred between December 2017 and December 2023. A copy of the IESO Transmission Rights Clearing Account Disbursement webpage notices during this period are attached together as **Exhibit "H".**

IESO changed its approach in 2006

36. In my view, the IESO's unfair approach toward Nexus Energy in this case goes against MACD's compliance and enforcement approach in place for almost 20 years.

37. My understanding is that beginning in or around 2006, the IESO moved away from a compliance and enforcement approach toward failed intertie transactions to an automated failure charge methodology. A copy of an IESO report entitled "Intertie Transactions Failure Guidelines" dated November 18, 2005 is attached as **Exhibit "I"**. A copy of the IESO's 2006 market rule amendment proposals MR-00308-R00 to MR-00308-R04 are attached together as **Exhibit "J"**.

38. Following this change in the IESO's approach in 2006, I had understood that failed intertie transactions for certain "seams issue" would be coded "OTH" by the IESO and could therefore attract an IFC or EFC. A copy of Chapters 1, 3, 7, 9 and 11 of the IESO Market Rules are attached respectively as **Exhibits "K", "L", "M", "N" and "O"**. A copy of IESO Market Manuals 2.6, 5.5, and IESO Market Manual entitled "IESO Charge Types and Equations" are attached as **Exhibits "P", "Q",** and **"R"** respectively.

39. In this case, the IESO charged Nexus Energy over $1,663,000 in IFCs and EFCs between 2017 and 2023 including for many of the Subject Transactions. Nexus Energy has paid these IFCs and EFCs and they are not in dispute in this arbitration.

40. Further, even if Nexus Energy did not agree with the OTH coding for the Subject Transactions in real-time (i.e. when the transactions failed to flow), in many cases Nexus Energy would not dispute the OTH coding because the corresponding IFC or EFC was

relatively small on a per transaction basis and it was not worth the time and internal resources to engage in the notice of disagreement process with the IESO.

41. In contrast to IFCs and EFCs, and as described in more detail below, I was not aware of any additional type of charge called “avoided congestion rents” or that the IESO had the authority to impose such charges.

The IESO only changed IFCs and EFCs to include congestion costs in May 2025

42. It was only in May 2025 when the IESO changed IFCs and EFCs to include congestion rents (such as those that are being challenged in this arbitration). For clarity, these changes were implemented after the Notice of Non-Compliance was issued to Nexus Energy and my understanding is that they do not apply retroactively to the Subject Transactions.

43. The IESO has in the past updated which types of intertie transaction failures it will or will not code as “OTH”. For instance, the IESO conducted a public stakeholder engagement in May 2024 which I attended virtually and during which the IESO explained that sometimes intertie transactions fail over the Ontario-MISO intertie due to a market participant’s (i) inability to acquire transmission service from MISO; or (ii) inability to acquire ramp capacity from MISO. Although such reasons are arguably outside of a market participant’s control, the IESO expressly advised market participants it would be coding such transaction failures as “OTH” on a go-forward basis. A copy of the IESO’s May 2024 stakeholder engagement slide deck is attached as **Exhibit “S”**.

44. Nowhere in this May 2024 stakeholder engagement slide deck does it state that market participants could become separately liable for congestion rents or "avoided congestion rents" pertaining to failed intertie transactions. I do not recall the IESO saying at any time during the May 2024 stakeholder engagement session that market participants could become liable for "avoided congestion rents".

45. IFCs and EFCs, including the formulae used to calculate them, are also set out in the IESO's publicly available training guide entitled "Interjurisdictional Energy Trading". A copy of that training guide dated January 2014 is attached as **Exhibit "T"**. Nowhere in the training manual does it state the IESO may also seek to recover "avoided congestion rents".

46. To my understanding, it was not until the implementation of the IESO's Market Renewal Program in May 2025 that congestion rents became included in the formulae for calculating IFCs and EFCs.

47. As part of its Market Renewal Program stakeholder engagement, the IESO also publicly presented to market participants that congestion rents would begin to be included in IFCs and EFCs beginning in May 2025. A copy of the IESO's associated stakeholder engagement slide deck is attached as **Exhibit "U"** (see slides 46 and 47).

48. As part of its Market Renewal Program implementation, the IESO also published an updated version of its Interjurisdictional Energy Trading training guide which expressly includes congestion rents in the calculation of IFCs and EFCs. A copy of the

Interjurisdictional Energy Trading training guide dated May 2025 is attached as **Exhibit "V"**.

Perfunctory Negotiations by IESO

49. To challenge the Notice of Non-Compliance, I understand that Nexus Energy has to use the dispute resolution process under the IESO Market Rules. As part of that dispute resolution process, I understand the parties are required to participate in good faith negotiations.

50. Accordingly, following receipt of the Notice of Non-Compliance on December 17, 2024, Nexus Energy requested a "good faith negotiations" meeting with the IESO. The meeting took place virtually (using Microsoft Teams) on January 15, 2025. I attended the meeting together with Ali Qaisar, on behalf of Nexus Energy. The representatives for MACD that attended the meeting were mostly the same as those that attended the September 4, 2024 meeting (which I also attended), including internal MACD lawyers and Robert (Bob) Yeoman.

51. We were disappointed that no one attended the January 15, 2025 meeting on behalf of the IESO other than the same MACD staff that were involved in preparing the Notice of Alleged Breach and Notice of Non-Compliance, including Bob Yeoman.

52. As we were engaging with the same MACD staff with whom we had already had meetings on each of April 12, 2024 and September 4, 2024, it became quickly apparent to us that the "good faith negotiations" meeting would not result in a resolution to the dispute.

53. We then proceeded to explore the next step of the IESO dispute resolution process, namely mediation. The mediation was also short and unsuccessful.

54. Prior to this dispute, I am not aware of Nexus Energy being the subject of any compliance investigation by the IESO nor by the regulator for any other energy trading market jurisdictions in which Nexus Energy participates.

55. This dispute not only has adversely impacted our business in Ontario, but also has adversely impacted our business reputation and ability to participate in other trading markets.

56. For example, on September 22, 2025 I received an email from Southwest Power Pool, Inc. – a neighbouring trading jurisdiction that operates electricity markets across 14 states in the United States – saying that we had to increase the amount of security on deposit in order to maintain our participation status and doubling our margin requirements. The email states in part that “[b]eing found in violation of market rules at another ISO/RTO [the IESO], and being ordered to pay back $2.08 MM is a serious issue that we agree should result in additional financial assurance”. A copy of that September 22, 2025 email is attached as **Exhibit “W”**.

SWORN BEFORE ME by Mr. ROBIN DOOLITTLE in the City of Toronto, in the Province of Ontario before me at the City of Toronto, in the Province of Ontario on October 29, 2025, in accordance with O. Reg 431/20, Administering Oath or Declaration Remotely.

Commissioner for Taking Affidavits
(or as may be)

Robin Doolittle

October 29, 2025

Keith Edward Hickey, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law

Expires June 24, 2027.

Exhibit “A”

Curriculum Vitae of Mr. Robin Doolittle

Exhibit “A”

to the Affidavit of Robin Doolittle

Sworn before me on October 29, 2025, in accordance with O. Reg. 431/20,
Administering Oath or Declaration Remotely



Commissioner for Taking Affidavits
(or as may be)

October 29, 2025

Keith Edward Hickey, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.

Expires June 24, 2027.

ROBIN DOOLITTLE 416 670 3642 doolittlerobin@gmail.com

Nexus Energy Inc. – Oct 2018 – Present

Managing Director – Head of Trading (Jan 2020 - Present)

- Responsible for all trading activities.
- Expanded trading group by recruiting 3 West Traders and opening a Calgary Office.
- Responsible for risk management of Ontario Deal Origination customer positions.

Director – Head of Financial Trading (Oct 2018 - Jan 2020)

- Built out financial trading desk including mid and back-office functions.
- Recruited, hired, and trained traders.
- Assisted in expansion of team to include Ontario Deal Origination book of business.

RBC Capital Markets Power Trading – Jul 2007 - Nov 2017

Director (Dec 2010 - Nov 2017)

- Cash focused trading in Northeast power markets (IESO, NYISO, ISONE, PJM, MISO).
- High performance P&L contributor.
- Provided coverage for term trading.
- Managed Realtime Power trading desk with strong P&L results.
- Oversaw all Realtime desk functions including strategy development, trade execution, risk framework, regulatory monitoring, ISO invoicing, scheduling, and hiring.
- Primary liaison between Power Trading and IT group dealing with systems issues.

Realtime Trader (Jul 2007 - Dec 2010)

- Recruited from Ontario Power Generation to assist in building Realtime desk from scratch.
- Developed trading strategies, market tools, and procedures.
- Top performer over 3 years leading to promotion to desk supervisor.
- Extensive fundamental knowledge of Northeast power grid including generation, transmission, and other market mechanisms.

Ontario Power Generation (OPG) Energy Markets – May 2000 - Jul 2007

Market Operations Coordinator

- Member of Portfolio Management Centre (PMC) responsible for 24/7 optimization of OPG's generation assets (22,000 MW).
- Primary liaison between plant groups (Fossil, Nuclear, Hydroelectric) and Independent Electricity System Operator (IESO).
- Responsible for offer submission to IESO administered markets based on unit availability, physical constraints, and market outlook.

Trading and Fuels Logistics Coordinator

- Responsible for deal entry, risk limit monitoring, position reporting, bid/offer submission, and NERC tagging.

- Analysis and support for all trading desks (Term, Cash, Realtime) in Ontario and surrounding electricity markets (NYISO, MISO, PJM, ISONE).
- Responsible for natural gas nominations to TransCanada Pipelines and Union Gas on behalf of Energy Markets for delivery to OPG's duel-fuel station (Lennox TGS).
- Monitored residual fuel oil inventory, consumption, and delivery to Lennox TGS.

EDUCATION

Queen's University, Kingston ON - Bachelor of Science in Electrical Engineering – 1997 - 2001

- Recipient of Chernoff Family Award (top Queen's entrance scholarship).
- Power option with concentration in electricity, communications, and power electronics.
- Honours distinction for 4 years.
- Courses in power, power electronics, microwave and fiber-optic communications, logic, and business administration.

Exhibit “B”

Participation Agreement between Nexus Energy and IESO signed August 16, 2017

Exhibit “B”

to the Affidavit of Robin Doolittle

Sworn before me on October 29, 2025, in accordance with O. Reg. 431/20,
Administering Oath or Declaration Remotely



Commissioner for Taking Affidavits
(or as may be)

October 29, 2025

Keith Edward Hickey, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.

Expires June 24, 2027.

PUBLIC

MDP_AGR_0012

AGREEMENT

ieso
Connecting Today.
Powering Tomorrow.

Participation Agreement

Between

NEXUS ENERGY INC.

As Applicant

and

INDEPENDENT ELECTRICITY SYSTEM OPERATOR

August 16, 2017

Confidential to IESO and Participant

THIS AGREEMENT dated this 16th day of August, 2017

BETWEEN:

NEXUS ENERGY INC., a Corporation duly Incorporated under the laws of ON, having its registered address at 333 Bay Street Suite 635, Toronto, ON M5H 2R2, and its principal place of business at 333 Bay Street Suite 635, Toronto, ON M5H 2R2

(the "Applicant")

- and -

The Independent Electricity System Operator, a corporation incorporated by the *Electricity Act, 1998,* S.O. 1998, c. 15, Sched. A, having its registered address at Station 'A', Box 4474, Toronto, Ontario M5W 4E5 and its principal place of business at Station 'A', Box 4474, Toronto, Ontario M5W 4E5

(the "*IESO*").

WHEREAS:

A. The Applicant wishes to participate in the *IESO-administered markets* and/or programs.

B. The *market rules* for the Ontario electricity market stipulate that no person shall participate in the *IESO-administered markets* or cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid* unless that person has been authorized by the *IESO* to do so.

C. The *market rules* further provide that no person shall be authorized to participate in the *IESO-administered markets* and/or programs unless the *IESO* is satisfied that that person agrees to be bound by the *market rules* by executing a *participation agreement*.

D. The Applicant is in the process of satisfying the conditions to becoming a *market participant*, and/or program participant.

E. The Applicant and the *IESO* wish to enter into this Agreement in part to satisfy the conditions contained in the *market rules* that a *participation agreement* be executed in order for the *IESO* to authorize a *market participant* and/or program participant.

F. The *market rules* provide that they will have the effect of a contract between the *IESO* on the one hand and each *market participant* and/or program participant on the other hand, by virtue of the execution of a *participation agreement.*

G. While completing the participant authorization tasks or once becoming a *market participant* and/or program participant, the Applicant may obtain access to *confidential information* when using or connecting to *IESO's* information systems.

H. The Applicant and the IESO hereby acknowledge that, unless otherwise specified, all of the terms of this *Agreement* are intended to apply to the Applicant whenever it is accessing the *IESO's* information systems from and including the date this *Agreement* is signed by the Applicant, even if it is signed prior to the Applicant's completion of the participant authorization tasks.

NOW therefore, in consideration of the mutual covenants set forth herein and of other good and valuable consideration, the receipt and adequacy of which is hereby acknowledged, the *Parties* agree as follows:

ARTICLE 1
INTERPRETATION

1.1 **Incorporation of *Market Rules* Definitions:** Subject to section 1.2, italicized expressions used in this Agreement have the meanings ascribed thereto in Chapter 11 of the *market rules*.

1.2 **Supplementary Definitions:** In this *Agreement*, the following italicized expressions shall have the meanings set out below unless the context otherwise requires:

"Accredited Investor" shall have the meaning attributed thereto in National Instrument 45-106 – Prospectus and Registration Exemptions, as made by the Canadian Securities Administrators, a list of the criteria is attached hereto as Schedule 2;

"*Agreement*" means this Agreement, including the Schedules to this Agreement, and the expressions "hereof", "herein", "hereto", "hereunder", "hereby" and similar expressions refer to this Agreement and not to any particular section or other portion of this Agreement; and

"*Party*" means a party to this *Agreement* and "*Parties*" means every *Party*.

1.3 **Interpretation:** In this *Agreement*, unless the context otherwise requires:

1.3.1 words importing the singular include the plural and vice versa;

1.3.2 words importing a gender include any gender;

1.3.3 when italicized, other parts of speech and grammatical forms of a word or phrase defined in this *Agreement* have a corresponding meaning;

1.3.4 the expression "person" includes a natural person, any company, partnership, trust, joint venture, association, corporation or other private or public body corporate, and any government agency or body politic or collegiate;

1.3.5 a reference to a thing includes a part of that thing;

1.3.6 a reference to an article, section, provision or schedule is to an article, section, provision or schedule of this Agreement;

1.3.7 a reference to any statute, regulation, proclamation, order in council, ordinance, by-law, resolution, rule, order or directive includes all statutes, regulations, proclamations, orders in council, ordinances, by-laws or resolutions, rules, orders or directives varying, consolidating, re-enacting, extending or replacing it and a reference to a statute includes all regulations, proclamations, orders in council, rules and by-laws of a legislative nature issued under that statute;

1.3.8 a reference to a document or provision of a document, including this *Agreement* and the *market rules* or a provision of this *Agreement* or the *market rules*, includes an amendment or supplement to, or replacement or novation of, that document or that provision of that document, as well as any exhibit, schedule, appendix or other annexure thereto;

1.3.9 a reference to a person includes that person's heirs, executors, administrators, successors and permitted assigns;

1.3.10 a reference to sections of this *Agreement* or of the *market rules* separated by the word "to" (*i.e.*, "sections 1.1 to 1.4") shall be a reference to the sections inclusively;

1.3.11 the expression "including" means including without limitation, the expression "includes" means includes without limitation and the expression "included" means included without limitation; and

1.3.12 a reference in this *Agreement* to the *market rules* includes a reference to any forms and *market manuals* established by the *IESO* and to any policies, guidelines or other documents adopted by the *IESO Board*, in each case as *published* pursuant to section 7.7 of Chapter 1 of the *market rules*.

1.4 **Headings:** The division of this *Agreement* into articles and sections and the insertion of headings are for convenience of reference only and shall not affect the interpretation of this *Agreement*, nor shall they be construed as indicating that all of the provisions of this *Agreement* relating to any particular topic are to be found in any particular article, section, subsection, clause, provision, part or schedule.

ARTICLE 2
MARKET RULES

2.1 ***Market Rules* Govern:** In the event of any inconsistency between this *Agreement* and the *market rules*, the *market rules* shall prevail to the extent of the inconsistency.

ARTICLE 3
COMPLIANCE WITH MARKET RULES

3.1 **Applicant Compliance:** The Applicant hereby agrees to be bound by and to comply with all of the provisions of the *market rules* so far as they are applicable to the Applicant, including once it has been authorized by the *IESO* as a *market participant* or has successfully registered with the *IESO* as a program participant. Without limiting the generality of the foregoing, if the Applicant is or intends to become a program participant, the Applicant shall comply with and be bound by the provisions of Chapter 1, section 13 and Chapter 3, Section 5.

3.2 ***IESO* Compliance:** The *IESO* hereby agrees to be bound by and to comply with all of the provisions of the *market rules* so far as they are applicable to the *IESO*.

3.3 **Acknowledgment of Amendments:** The Applicant acknowledges and agrees that the *market rules* and the policies, guidelines and other documents referred to in section 1.3.12 may be amended by the *IESO* from time to time in accordance with the *market rules*.

ARTICLE 4
REPRESENTATIONS AND WARRANTIES

4.1 **Representations and Warranties of the *IESO*:** The *IESO* hereby represents and warrants as follows to the Applicant, and acknowledges and confirms that the Applicant is relying on such representations and warranties in applying to become authorized as a *market participant* and/or registered as a program participant:

4.1.1 the execution, delivery and performance of this *Agreement* by it has been duly authorized by all necessary corporate and/or governmental action; and

4.1.2 this *Agreement* constitutes a legal and binding obligation on the *IESO*, enforceable against the *IESO* in accordance with its terms.

4.2 **Representations and Warranties of the Applicant:** The Applicant hereby represents and warrants as follows to the *IESO* and acknowledges and confirms that the *IESO* is relying on such representations and warranties without independent inquiry (save and except for any testing or inspection that the *IESO* may have participated in) (i) to ascertain whether the Applicant satisfies the requirements for authorization as a *market participant* and/or registration with the *IESO* as a program participant; (ii) to ascertain whether the Applicant is ready and able to participate in the *IESO-administered markets* and/or programs, and, where applicable, to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid*; and (iii) to authorize the Applicant as a *market participant* and/or program participant under the *market rules*:

4.2.1 it is a Corporation duly Incorporated and existing under the laws of ON;

4.2.2 it has all the necessary corporate power to enter into and perform its obligations under this *Agreement*;

4.2.3 the execution, delivery and performance of this *Agreement* by it has been duly authorized by all necessary corporate and/or governmental action and in the Applicant's good faith belief and after making reasonable inquiry does not (or would not with the giving of notice, the lapse of time or the happening of any other event or condition) result in a violation or a breach of or a default under or give rise to a right of termination, greater rights or increased costs, amendment or cancellation or the acceleration of any obligation under (i) any charter or by-law instruments of the Applicant; (ii) any contracts or instruments to which the Applicant is a party or by which the Applicant is bound; or (iii) any laws applicable to it;

4.2.4 the individual(s) executing this *Agreement*, and any document in connection herewith, on behalf of the Applicant have been duly authorized to execute this *Agreement* and have the full power and authority to bind the Applicant;

4.2.5 this *Agreement* constitutes a legal and binding obligation on the Applicant, enforceable against the Applicant in accordance with its terms;

4.2.6 except for authorization as a *market participant* and/or registration as a program participant, and registration of any of its *facilities* or *boundary entities* by the *IESO* pursuant to the *market rules,* as applicable, it holds all permits, licenses and other authorizations that may be necessary to enable it to carry on the business and perform the functions and obligations of a *market participant* and/or program participant, as applicable, as described in the *market rules* and in this *Agreement*;

4.2.7 the information provided in support of its *application for authorization to participate* as a *market participant* and/or registration as a program participant, is true, accurate and complete in all respects;

4.2.8 subject to any *exemption* that the Applicant may have obtained, its *participant workstation*, if any, complies with or will comply prior to the first date the Applicant participates in the *IESO-administered markets* and/or programs, with all applicable technical requirements set forth in Appendix 2.2 of the *market rules*;

4.2.9 the Applicant has or will have prior to the first date the Applicant participates in the *IESO-administered markets* and/or programs, adequate qualified employees and other personnel and organizational and other arrangements that are sufficient to enable it to perform all of the functions and obligations applicable to *market participants* and/or program participants, the class of *market participant* and/or

program participant of which the Applicant forms part and the *IESO-administered market* and/or program in which the Applicant wishes to participate;

4.2.10 subject to the granting of any exemptions for which the Applicant has applied, the *facilities* or *boundary entities* that the Applicant has registered with the *IESO* and the equipment related thereto comply, or will comply prior to the earlier of the first date the Applicant participates in the *IESO-administered markets* and/or programs and the date the Applicant's *facility* connects to the *IESO-controlled grid*, with all applicable technical requirements as set forth in the *market rules* applicable to all *market participants* and/or program participants, the class of *market participant* and/or program participant of which the Applicant forms part and the *IESO-administered markets* and/or programs in which the Applicant wishes to participate;

4.2.11 subject to the granting of any exemptions for which the Applicant has applied, the Applicant has provided, or will provide to the *IESO* prior to the earlier of the first date the Applicant participates in the *IESO-administered markets* and/or programs and the date the Applicant's *facility* connects to the *IESO-controlled grid*, all of the information required to be submitted in support of the registration of the *facilities* or *boundary entities* that the Applicant has registered with the *IESO* and the equipment related thereto and that such information is true, accurate and complete in all respects;

4.2.12 if the Applicant is or intends to be a *TR participant*, the Applicant has read, has full knowledge of and understands the provisions of the *market rules* and National Instrument 45-106 – *Prospectus and Registration Exemptions*, as made by the Canadian Securities Administrators (as the same may be amended, modified, supplemented and/or replaced from time to time, "NI 45-106") and the Applicant warrants that it is an *Accredited Investor* as such term is defined in NI 45-106 and understands that it must remain so in order to maintain authorization as a *financial market participant*; and

4.2.13 if the Applicant is or intends to be a *TR participant*, the Applicant hereby undertakes, covenants and agrees to advise the *IESO* in writing forthwith upon becoming aware of any event, circumstance or condition known to it that individually or together with all other such events, circumstances or conditions has, had or could have the effect of resulting in the Applicant no longer qualifying as an *Accredited Investor*.

ARTICLE 5
TERM AND TERMINATION

5.1 **Term:** This *Agreement* shall come into force on the date first noted above and shall remain in full force and effect until terminated in accordance with section 5.2 or section 5.3.

5.2 **Termination Upon Termination Order:** Subject to sections 5.4 and 5.5, this *Agreement* shall automatically terminate upon the issuance to the Applicant of a *termination order* by the *IESO* in accordance with section 6.4 of Chapter 3 of the *market rules.*

5.3 **Termination by Applicant:** Subject to section 5.6, this Agreement shall automatically terminate once the Applicant has ceased to be a *market participant* in accordance with the provisions of Section 9 of Chapter 2 of the *market rules* or ceased to be a program participant.

5.4 **Ongoing Liability:** Notwithstanding the provisions of section 5.2 or section 5.3 above, if the Applicant becomes a *terminated market participant* or is terminated as a program participant or otherwise ceases to be a *market participant* or program participant, as the case may be, the Applicant shall remain subject to and liable for all of its obligations and liabilities as a *market participant* and/or program participant which were incurred or arose under the *market rules* prior to the date on which the *termination order* was issued or the date on which the Applicant otherwise ceased to be a *market participant* and/or program participant, as the case may be, regardless of the date on which any claim relating thereto may be made.

5.5 **Confidentiality:** Notwithstanding the provisions of section 5.2 or section 5.3 above, if the Applicant becomes a *terminated market participant* or is terminated as a program participant or otherwise ceases to be a *market participant* and/or program participant, as the case may be, the Applicant shall remain subject to any confidentiality provisions contained in the *market rules* for all information obtained by or provided to the Applicant while the Applicant was a *market participant* and/or program participant.

5.6 **Survival:** Notwithstanding any provision to the contrary and for greater certainty, the terms of section 5.4 and section 5.5 of this *Agreement* shall survive any termination of this *Agreement* without limit as to time.

ARTICLE 6
LIABILITY AND INDEMNIFICATION

6.1 **Limitation of Liability:** The provisions of section 13 of Chapter 1 of the *market rules* apply to this *Agreement* and are hereby incorporated by reference herein, with all references in such section to a *market participant* and/or program participant being deemed to be references to the Applicant.

ARTICLE 7
MISCELLANEOUS

7.1 **Amendment:** No amendment of this *Agreement* shall be effective unless made in writing and signed by the *Parties*.

7.2 **Assignment:** This *Agreement* is personal to the *Parties*. Neither the rights nor the obligations of either *Party* under this *Agreement* may be assigned to any other person voluntarily, by operation of law, or otherwise, except with the other *Party's* prior written consent. No assignment made without the other *Party's* consent shall relieve a *Party* of its obligations under this Agreement. Notwithstanding the foregoing and for greater certainty, except as otherwise provided in the *market rules* or in any standard, policy, guideline, procedure or other document established by the *IESO* pursuant to the *market rules,* the Applicant may use such information systems, communication systems, business processes, personnel, service providers or other agents as the Applicant, in its sole discretion, considers appropriate for the purpose of assisting in the performance of its obligations under the *market rules* and under such standard, policy, guideline, procedure or other document provided that, as between the *IESO* and the Applicant:

7.2.1 the Applicant shall be bound by and fully responsible for all acts or omissions of its personnel, service providers or other agents; and

7.2.2 the Applicant shall remain solely responsible and liable to the *IESO* for the due performance of such obligations.

7.3 **Successors and Assigns**: This *Agreement* shall enure to the benefit of, and be binding on, the *Parties* and their respective heirs, administrators, executors, successors and permitted assigns.

7.4 **Further Assurances:** Each *Party* shall promptly execute and deliver or cause to be executed and delivered all further documents and do such further acts and things as the other *Party* may reasonably request to evidence, carry out and give full effect to the terms, conditions, intent and meaning of this *Agreement.*

7.5 **Exemption**: An exemption of any default, breach or non-compliance under this *Agreement* is not effective unless in writing and signed by the *Party* to be bound by the exemption. No exemption will be inferred or implied by any failure to act or by the delay in acting by a *Party* in respect of any default, breach or non-observance or by anything done or omitted to be done by the other *Party*. The exemption by a *Party* of any default, breach or non-compliance under this *Agreement* shall not operate as an exemption of that *Party's* rights under this *Agreement* in respect of any continuing or subsequent default, breach or non-observance (whether of the same or any other nature).

7.6 **Severability**: Each provision in this *Agreement* is distinct and severable. If any provision of this *Agreement*, in whole or in part, is or becomes illegal, invalid or unenforceable in any jurisdiction, the illegality, invalidity or unenforceability of that provision, in whole or in part, shall not affect the legality, validity or enforceability of the remaining provisions of this *Agreement* in any other jurisdiction.

7.7 **Notices**: Any notice, demand, consent, request or other communication required or permitted to be given or made under this *Agreement* shall:

7.7.1 be given or made in the manner set forth in section 8.1 of Chapter 1 of the *market rules*;

7.7.2 be addressed to the other *Party* in accordance with the information set forth in Schedule 1 to this *Agreement*; and

7.7.3 be treated as having been duly given or made in accordance with the provisions of section 8.2 of Chapter 1 of the *market rules*.

Either *Party* may change its address and representative as set forth in Schedule 1 to this *Agreement* by written notice to the other *Party* given as aforesaid. Such change shall not constitute an amendment to this *Agreement* for the purposes of the application of section 7.1.

7.8 **Authority:** The Applicant hereby represents that the Applicant's representative(s) listed in Schedule 1 to this *Agreement* is hereby designated to act as the primary contact on behalf of the Applicant and to designate a rights administrator on behalf of the Applicant who may in turn add additional person(s) as user(s)/custodian(s) of the Applicant. The rights administrator is the person who requests system access to *IESO's* information systems on behalf of the Applicant. Without in any way limiting the rights and obligations under sections 7.2.1 and 7.2.2 of this *Agreement*, the Applicant shall be bound by and is solely responsible for all acts or omissions taken or made by its rights administrator and users in respect of the *IESO's* information systems. Anything said or done by the rights administrator and/or the Applicant's users shall be deemed to have been said or done by the Applicant under this *Agreement*.

7.9 **Governing Law:** This *Agreement* shall be governed by and construed in accordance with the laws of the Province of Ontario and the federal laws of Canada applicable therein, without regard to principles of conflicts of laws that would impose a law of another jurisdiction.

7.10 **Attornment**: Subject to section 2 of Chapter 3 of the *market rules*, the *license* of each *Party,* section 36 of the *Electricity Act, 1998* (Ontario) and section 33 of the *Ontario Energy Board Act, 1998* (Ontario), each *Party* agrees (i) that any action or proceeding relating to this *Agreement* shall be brought in a court of competent jurisdiction in the Province of Ontario, and for that purpose now irrevocably and unconditionally attorns and submits to the exclusive jurisdiction of such Ontario court and all courts competent and with jurisdiction to hear appeals therefrom; (ii) that it irrevocably waives any right to, and will not, oppose any such Ontario action or proceeding on any jurisdictional basis, including forum non conveniens; and (iii) not to oppose the enforcement against it in any other jurisdiction of any judgment or order duly obtained from an Ontario court as contemplated by this section 7.10.

7.11 **Counterparts:** This *Agreement* may be executed in any number of counterparts, each of which shall be deemed to be an original and all of which taken together shall be deemed to constitute one and the same instrument. Counterparts may be executed either in original

or faxed form and the *Parties* adopt any signatures received by a receiving facsimile machine as original signatures of the *Parties*; provided, however, that any *Party* providing its signature in such manner shall promptly forward to the other *Party* an original signed copy of this *Agreement* which was so faxed.

IN WITNESS WHEREOF the *Parties* have, by their duly appointed and authorized representatives, executed this *Agreement.*

NEXUS ENERGY INC.

Authorized Representative(s) - Person responsible for contractually binding your organization with the IESO:

By: _____ c/s
Name: Tong Yang
Position: Director
Address: 333 Bay Street Suite 635
Toronto, ON M5H 2R2

Email Address: external.relations@NexusEnergyCanada.com
Phone: 6472871918

By: _____ c/s
Name:
Position:
Address:

Email Address:
Phone:

Independent Electricity System Operator

By: _____
Name: For Mauro Facca, P.Eng.
Position: Acting Senior Manager, Models & Data

SCHEDULE 1
NOMINATED REPRESENTATIVES FOR OFFICIAL NOTIFICATIONS
[Section 7.7]

IESO

Name of *IESO* Representative:	Mauro Facca
Position: Acting	Senior Manager, Models & Data
Address:	Station A, Box 4474
City/Province/Postal Code:	Toronto, Ontario M5W 4E5
Email Address:	market.registration@ieso.ca
Phone:	905.855.6424

Applicant

Identify at least one Primary contact that will be responsible for day-to-day activities for your organization with the IESO.

Name of Primary Contact:	Tong Yang
Position:	Director
Address:	333 Bay Street Suite 635
City/Province/Postal Code:	Toronto, ON M5H 2R2
Email Address:	external.relations@NexusEnergyCanada.com
Phone:	6472871918
Fax:	

SCHEDULE 2

MEANING OF ACCREDITED INVESTOR

"accredited investor" means

(a) a Canadian financial institution, or a Schedule III bank;

(b) the Business Development Bank of Canada incorporated under the *Business Development Bank of Canada Act* (Canada);

(c) a subsidiary of any person referred to in paragraphs (a) or (b), if the person owns all of the voting securities of the subsidiary except the voting securities required by law to be owned by directors of that subsidiary;

(d) a person registered under the securities legislation of a jurisdiction of Canada as an adviser or dealer, other than a person registered solely as a limited market dealer under one or both of the *Securities Act* (Ontario) or the *Securities Act* (Newfoundland and Labrador);

(e) an individual registered or formerly registered under the securities legislation of a jurisdiction of Canada as a representative of a person referred to in paragraph (d);

(f) the Government of Canada or a jurisdiction of Canada, or any crown corporation, agency or wholly owned entity of the Government of Canada or a jurisdiction of Canada;

(g) a municipality, public board or commission in Canada and a metropolitan community, school board, the Comité de gestion de la taxe scolaire de I'ile de Montréal or an intermunicipal management board in Québec;

(h) any national, federal, state, provincial, territorial or municipal government of or in any foreign jurisdiction, or any agency of that government;

(i) a pension fund that is regulated by either the Office of the Superintendent of Financial Institutions (Canada) or a pension commission or similar regulatory authority of a jurisdiction of Canada;

(j) an individual who, either alone or with a spouse, beneficially owns, directly or indirectly, financial assets having an aggregate realizable value that before taxes, but net of any related liabilities, exceeds $1,000,000;

(k) an individual whose net income before taxes exceeded $200,000 in each of the 2 most recent calendar years or whose net income before taxes combined with that of a spouse

exceeded $300,000 in each of the 2 most recent calendar years and who, in either case, reasonably expects to exceed that net income level in the current calendar year;

(l) an individual who, either alone or with a spouse, has net assets of at least $5,000,000;

(m) a person, other than an individual or investment fund, that has net assets of at least $5,000,000 as shown on its most recently prepared financial statements;

(n) an investment fund that distributes or has distributed its securities only to:

i) a person that is or was an accredited investor at the time of the distribution,

(ii) a person that acquires or acquired securities in the circumstances referred to in sections 2.10 *[Minimum amount investment],* and 2.19 *[Additional investment in investment funds]*, or

(iii) a person described in paragraph (i) or (ii) that acquires or acquired securities under section 2.18 *[Investment fund reinvestment]*;

(o) an investment fund that distributes or has distributed securities under a prospectus in a jurisdiction of Canada for which the regulator or, in Québec, the securities regulatory authority, has issued a receipt;

(p) a trust company or trust corporation registered or authorized to carry on business under the *Trust and Loan Companies Act* (Canada) or under comparable legislation in a jurisdiction of Canada or a foreign jurisdiction, acting on behalf of a fully managed account managed by the trust company or trust corporation, as the case may be;

(q) a person acting on behalf of a fully managed account managed by that person, if that person:

(i) is registered or authorized to carry on business as an adviser or the equivalent under the securities legislation of a jurisdiction of Canada or a foreign jurisdiction, and

(ii) in Ontario, is purchasing a security that is not a security of an investment fund;

(r) a registered charity under the *Income Tax Act* (Canada) that, in regard to the trade, has obtained advice from an eligibility adviser or an adviser registered under the securities legislation of the jurisdiction of the registered charity to give advice on the securities being traded;

(s) an entity organized in a foreign jurisdiction that is analogous to any of the entities referred to in paragraphs (a) to (d) or paragraph (i) in form and function;

(t) a person in respect of which all of the owners of interests, direct, indirect or beneficial, except the voting securities required by law to be owned by directors, are

persons that are accredited investors;

(u) an investment fund that is advised by a person registered as an adviser or a person that is exempt from registration as an adviser; or

(v) a person that is recognized or designated by the securities regulatory authority or, except in Ontario and Québec, the regulator as:

(i) an accredited investor, or

(ii) an exempt purchaser in Alberta or British Columbia after this Instrument comes into force.

– End of Document –

Exhibit "C"

IESO Notice of Alleged Breach dated April 4, 2024

Exhibit "C"

to the Affidavit of Robin Doolittle

Sworn before me on October 29, 2025, in accordance with O. Reg. 431/20, Administering Oath or Declaration Remotely



Commissioner for Taking Affidavits
(or as may be)

October 29, 2025

Keith Edward Hickey, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.

Expires June 24, 2027.

ieso
Independent Electricity System Operator

Station A, Box 4474
Toronto, Ontario M5W 4E5
t 905 855 6100

www.ieso.ca

CONFIDENTIAL

Sent via: Workspaces

April 4, 2024

Francois Tardiff
Director of Risk and Regulatory
Nexus Energy Inc.
4789 Yonge Street, Suite 916
Ontario, Canada
M2N 0G3

Attention: Francois Tardiff,

Market Participant ID Number: 186267
Re: Notice Pursuant to Chapter 3, Section 6.2.3 of the Market Rules
Compliance Case: COM237240

A. Introduction

1. The *Market Rules for the Ontario Electricity Market* (the "**Market Rules**") require the Independent Electricity System Operator (the "**IESO**") to undertake such monitoring as it considers necessary to determine whether market participants are complying with the Market Rules.

2. Within the IESO, the responsibility of making determinations related to compliance assessment and enforcement has been delegated to the Vice-President of the Market Assessment & Compliance Division ("**MACD**").

3. Chapter 3, section 6.2.3 of the Market Rules requires the IESO to notify a market participant when it considers that the market participant may have breached or may

be breaching Market Rules and that, in the circumstances and if the breach is established, it would be appropriate that a sanction or sanctions be imposed.

4. Pursuant to Chapter 3, section 6.2.3 of the Market Rules, this letter constitutes notice that the IESO is considering whether Nexus Energy Inc. ("**NEXUS**") breached the following provision of the Market Rules:

    - Chapter 7, section 7.5.8A

5. MACD has commenced an investigation into whether this rule has been breached and may take further steps pursuant to sections 6.2.4.3, 6.2.4.4 and 6.6.10A of Chapter 3, following the opportunities to be afforded NEXUS in Sections E and F of this Notice.

6. If the investigation results in a determination that NEXUS has breached the Market Rules, possible sanctions under the Market Rules would be informed by the considerations detailed in Section D of this notice.

B. Details of the Possible Breaches of the Market Rules

i) Summary of the Relevant Events

7. This notice follows a review by MACD of intertie scheduling information pertaining to NEXUS's trading activity. Specifically, MACD believes that NEXUS has failed to schedule numerous intertie transactions other than for bona fide and legitimate reasons between December 28, 2017 and December 12, 2023 ("**Relevant Period**") at the Michigan-Ontario, Minnesota-Ontario, Manitoba-Ontario, Quebec-Ontario, and New York-Ontario interties. The total failed transactions for the Relevant Period that are the subject of this notice is 1,661. Appendix A particularizes details of the alleged breaches, including the date, hour, location and failed megawatts ("**MWs**") relating to each of the alleged failures to schedule intertie transactions.

8. MACD has also assessed, on a preliminary basis, that as a result of its failure to schedule the transactions identified in Appendix A, NEXUS has accrued certain benefits consisting of transmission rights payments as well as avoided congestion rent payments. The table below identifies these benefits by year.

Year	Avoided Congestion Rent Payments	Accrued Transmission Rights Benefits
2017	$7,760	$0
2018	$428,141	$0
2019	$180,244	$3,182
2020	$310,496	$1,138
2021	$89,837	$0
2022	$987,558	$7

2023	$74,773	$604
Grand Total	**$2,078,809**	**$4,931**

ii) Relevant Provisions of the Market Rules

9. Section 7.5.8A of Chapter 7 provides:

> A *registered market participant* associated with a *registered facility* that is a boundary entity shall, other than for the bona fide and legitimate reasons referred to in section 7.5.8B, schedule *energy* and *operating reserve*, in accordance with section 6.1.3, with the appropriate scheduling entity, or scheduling entities as the case may be.

10. Section 7.5.8B of Chapter 7 provides:

> The *IESO* may take actions pursuant to section 6.6.10A of Chapter 3 and shall assess a real-time import or export failure charge as determined in section 3.8C of Chapter 9 where a *registered market participant* associated with a *registered facility* that is a *boundary entity* fails to schedule *energy* or *operating reserve*, in accordance with section 6.1.3 of Chapter 7, with the appropriate scheduling entity, or scheduling entities as the case may be, according to the applicable *interchange schedule*, other than for bona fide and legitimate reasons as determined by the *IESO*. Bona fide and legitimate reasons shall include failures caused by actions and circumstances beyond the control of the *market participant* or due to *IESO* or external scheduling entity error or action, including those reasons specified in the applicable *market manual*.

11. The applicable market manual (Market Manual 4, Part 4.3, section 6.6.1 and Market Manual 5, Part 5.5, section 1.6.10.1) indicates, based on the reason code applied to a transaction failure, whether a transaction failure meets the criteria of a bona fide and legitimate reason as described in the Market Rules.

12. All transactions identified in Appendix A have the associated failure reason code as "OTH".

C. Details of The Evidence

13. The following sources of evidence pertaining to the relevant period inform MACD's understanding of this matter:

i) IESO data indicating NEXUS energy bids and/or offers.
ii) IESO control room logs.
iii) E-Tag curtailment notifications to NEXUS.

iv) Audio logs of the IESO's conversations with NEXUS.

v) IESO data indicating intertie schedules and failure reason codes.

vi) OATI E-tag data.

D. Details of Possible Sanctions

14. If MACD determines that NEXUS breached Chapter 7, section 7.5.8A of the Market Rules, MACD may issue one of the following sanctions: pursuant to Chapter 3, section 6.6.10A.1 of the Market Rules, issue a letter of non-compliance or impose a financial penalty in accordance with Chapter 3, sections 6.6.6 or 6.6.6A of the Market Rules; and, pursuant to Chapter 3, section 6.6.10A.2 of the Market Rules, adjust settlement amounts, including avoided congestion rents and transmission rights payments.

15. If, following the investigation, MACD determines that NEXUS breached the Market Rules, and decides to issue a financial penalty, then Chapter 3, sections 6.6.7 requires MACD to consider several factors in its assessment including any benefits NEXUS may have obtained as a result of Market Rules breach.

E. Right to Request a Meeting

16. In accordance with Chapter 3, section 6.2.3.5 of the Market Rules, NEXUS has the right to request a meeting to discuss this matter. Please contact us within ten (10) business days of receipt of this Notice if you wish to schedule a meeting. Failure to request the meeting within the prescribed time may forfeit your right to this meeting.

F. Timeline to Make Representations

17. In accordance with Chapter 3, section 6.2.3.4 of the Market Rules, NEXUS may make written representations to MACD within fifteen (15) business days of the date of this notice.

Written representations should be submitted via electronic mail or courier to:

Attention: Market Assessment and Compliance Division
Independent Electricity System Operator
Station A, Box 4474
Toronto, ON M5W 4E5
Email: MACD@ieso.ca

Subject: Response to Notice Pursuant to Chapter 3, Section 6.2.3, COM237240

If you have any questions or concerns, please feel free to contact Bob Yeoman at 905-330-4094 or Robert.Yeoman@ieso.ca.

Yours truly,



Glenn McDonald
Vice President,
Market Assessment & Compliance Division
Independent Electricity System Operator

Appendix A - Details of the Alleged Breaches

The entries below denote each instance in which NEXUS may have breached Chapter 7, section 7.5.8A of the Market Rules by failing to schedule intertie transactions other than for bona fide and legitimate reasons. The transactions identified below had all been coded as "OTH" as per Market Manual 4, Part 4.3 section 6.6.1 and Market Manual 5, Part 5.5, section 1.6.10.1.

Date	Hour	Resource Name	Scheduling Point	Scheduled MW	Failed MW
2017-12-28	1	MI.LUDINGTON.SINK.01	MISI	-1	-1
2017-12-29	15	NY.ROSETON.SINK.01	NYSI	-100	-100
2017-12-29	16	NY.ROSETON.SINK.01	NYSI	-100	-100
2017-12-30	2	NY.ROSETON.SINK.01	NYSI	-41	-21
2017-12-30	4	NY.ROSETON.SINK.01	NYSI	-60	-60
2017-12-31	13	NY.ROSETON.SINK.01	NYSI	-10	-10
2018-01-02	15	NY.ROSETON.SINK.02	NYSI	-14	-4
2018-01-02	19	NY.ROSETON.SINK.01	NYSI	-110	-35
2018-01-04	10	NY.ROSETON.SINK.02	NYSI	-10	-10
2018-01-08	10	NY.ROSETON.SINK.01	NYSI	-5	-5
2018-01-08	18	NY.ROSETON.SINK.01	NYSI	-20	-10
2018-01-09	19	NY.ROSETON.SINK.01	NYSI	-40	-5
2018-01-10	10	NY.ROSETON.SINK.01	NYSI	-60	-15
2018-01-11	1	NY.ROSETON.SINK.01	NYSI	-20	-10
2018-01-11	15	NY.ROSETON.SINK.01	NYSI	-20	-5
2018-01-14	20	NY.ROSETON.SINK.01	NYSI	-50	-50
2018-01-15	11	NY.ROSETON.SINK.02	NYSI	-10	-10
2018-01-23	13	NY.ROSETON.SINK.01	NYSI	-10	-10
2018-01-26	23	NY.ROSETON.SINK.01	NYSI	-100	-50
2018-01-31	15	NY.ROSETON.SINK.02	NYSI	-20	-10
2018-02-15	15	MI.LUDINGTON.SINK.01	MISI	-25	-25
2018-02-17	14	MI.LUDINGTON.SINK.01	MISI	-11	-11
2018-02-19	15	NY.ROSETON.SINK.01	NYSI	-150	-25
2018-02-26	13	NY.ROSETON.SINK.01	NYSI	-25	-10
2018-02-26	13	MI.LUDINGTON.SINK.01	MISI	-20	-20
2018-02-27	12	NY.ROSETON.SINK.02	NYSI	-25	-25
2018-02-27	12	NY.ROSETON.SINK.01	NYSI	-75	-40
2018-02-27	23	NY.ROSETON.SINK.02	NYSI	-50	-50
2018-02-28	9	MI.LUDINGTON.SINK.01	MISI	-50	-50
2018-02-28	10	MI.LUDINGTON.SINK.01	MISI	-50	-50
2018-02-28	13	NY.ROSETON.SINK.01	NYSI	-75	-75
2018-02-28	13	NY.ROSETON.SINK.02	NYSI	-25	-25
2018-02-28	16	MI.LUDINGTON.SINK.02	MISI	-25	-25

2018-02-28	17	MI.LUDINGTON.SINK.03	MISI	-22	-22
2018-03-01	10	NY.ROSETON.SINK.01	NYSI	-50	-50
2018-03-02	9	NY.ROSETON.SINK.01	NYSI	-30	-30
2018-03-02	13	NY.ROSETON.SINK.01	NYSI	-75	-55
2018-03-02	15	NY.ROSETON.SINK.01	NYSI	-75	-75
2018-03-02	16	NY.ROSETON.SINK.01	NYSI	-75	-75
2018-03-02	19	NY.ROSETON.SINK.02	NYSI	-25	-25
2018-03-03	10	MI.LUDINGTON.SINK.01	MISI	-25	-25
2018-03-03	10	NY.ROSETON.SINK.01	NYSI	-75	-35
2018-03-03	14	NY.ROSETON.SINK.01	NYSI	-50	-20
2018-03-09	13	NY.ROSETON.SINK.01	NYSI	-50	-20
2018-03-14	9	NY.ROSETON.SINK.01	NYSI	-25	-15
2018-03-14	10	NY.ROSETON.SINK.01	NYSI	-25	-15
2018-03-14	11	NY.ROSETON.SINK.02	NYSI	-50	-50
2018-03-16	21	MI.LUDINGTON.SINK.02	MISI	-10	-10
2018-03-18	12	NY.ROSETON.SINK.02	NYSI	-50	-20
2018-03-19	19	NY.ROSETON.SINK.01	NYSI	-50	-10
2018-04-04	13	NY.ROSETON.SINK.01	NYSI	-50	-10
2018-04-18	9	NY.ROSETON.SINK.01	NYSI	-25	-25
2018-04-30	11	NY.ROSETON.SINK.01	NYSI	-75	-15
2018-04-30	12	NY.ROSETON.SINK.01	NYSI	-25	-10
2018-05-01	13	NY.ROSETON.SINK.01	NYSI	-75	-25
2018-05-01	14	NY.ROSETON.SINK.01	NYSI	-75	-10
2018-05-07	13	NY.ROSETON.SINK.01	NYSI	-60	-60
2018-05-10	9	NY.ROSETON.SINK.01	NYSI	-50	-25
2018-05-10	10	NY.ROSETON.SINK.01	NYSI	-37	-37
2018-05-10	11	NY.ROSETON.SINK.01	NYSI	-25	-25
2018-05-12	17	NY.ROSETON.SINK.01	NYSI	-125	-25
2018-05-13	16	NY.ROSETON.SINK.01	NYSI	-125	-25
2018-05-14	12	NY.ROSETON.SINK.01	NYSI	-50	-10
2018-05-14	12	NY.ROSETON.SINK.02	NYSI	-25	-25
2018-05-14	14	NY.ROSETON.SINK.01	NYSI	-50	-15
2018-05-16	1	NY.ROSETON.SINK.02	NYSI	-10	-10
2018-05-16	9	NY.ROSETON.SINK.02	NYSI	-15	-15
2018-05-16	16	NY.ROSETON.SINK.01	NYSI	-50	-5
2018-05-17	10	MI.LUDINGTON.SINK.01	MISI	-25	-25
2018-05-17	11	NY.ROSETON.SINK.02	NYSI	-25	-25
2018-05-17	16	NY.ROSETON.SINK.01	NYSI	-75	-15
2018-05-18	10	NY.ROSETON.SINK.01	NYSI	-50	-20
2018-05-18	11	NY.ROSETON.SINK.01	NYSI	-50	-20
2018-05-18	12	NY.ROSETON.SINK.01	NYSI	-50	-20

2018-05-18	12	MI.LUDINGTON.SINK.02	MISI	-11	-11
2018-05-18	13	NY.ROSETON.SINK.01	NYSI	-14	-4
2018-05-18	14	NY.ROSETON.SINK.01	NYSI	-50	-25
2018-05-18	15	NY.ROSETON.SINK.01	NYSI	-50	-25
2018-05-18	16	NY.ROSETON.SINK.01	NYSI	-50	-25
2018-05-18	17	NY.ROSETON.SINK.01	NYSI	-50	-15
2018-05-18	17	NY.ROSETON.SINK.02	NYSI	-50	-50
2018-05-19	16	NY.ROSETON.SINK.02	NYSI	-35	-10
2018-05-19	17	NY.ROSETON.SINK.02	NYSI	-25	-25
2018-05-20	1	NY.ROSETON.SINK.02	NYSI	-102	-2
2018-05-20	15	NY.ROSETON.SINK.02	NYSI	-75	-25
2018-05-20	23	NY.ROSETON.SINK.02	NYSI	-75	-35
2018-05-21	7	NY.ROSETON.SINK.02	NYSI	-25	-25
2018-05-21	8	NY.ROSETON.SINK.02	NYSI	-25	-25
2018-05-21	9	NY.ROSETON.SINK.01	NYSI	-100	-57
2018-05-21	11	NY.ROSETON.SINK.01	NYSI	-100	-30
2018-05-22	1	NY.ROSETON.SINK.02	NYSI	-60	-60
2018-05-22	2	NY.ROSETON.SINK.02	NYSI	-40	-20
2018-05-22	4	NY.ROSETON.SINK.02	NYSI	-60	-60
2018-05-22	10	MI.LUDINGTON.SINK.01	MISI	-25	-25
2018-05-22	12	NY.ROSETON.SINK.02	NYSI	-50	-25
2018-05-25	18	MD.CALVERTCLIFF.SINK.05	MISI	-20	-20
2018-05-27	5	NY.ROSETON.SINK.02	NYSI	-36	-36
2018-05-30	16	MI.LUDINGTON.SINK.20	MISI	-200	-200
2018-06-02	20	NY.ROSETON.SINK.01	NYSI	-50	-25
2018-06-04	8	NY.ROSETON.SINK.02	NYSI	-100	-50
2018-06-04	9	NY.ROSETON.SINK.02	NYSI	-50	-50
2018-06-04	11	NY.ROSETON.SINK.02	NYSI	-50	-50
2018-06-04	14	NY.ROSETON.SINK.02	NYSI	-50	-50
2018-06-06	9	NY.ROSETON.SINK.01	NYSI	-22	-22
2018-06-06	14	NY.ROSETON.SINK.02	NYSI	-50	-50
2018-06-08	11	NY.ROSETON.SINK.02	NYSI	-96	-21
2018-06-10	17	NY.ROSETON.SINK.04	NYSI	-25	-25
2018-06-11	16	NY.ROSETON.SINK.04	NYSI	-100	-100
2018-06-18	14	MD.CALVERTCLIFF.SINK.01	MISI	-21	-21
2018-06-18	16	MI.LUDINGTON.SINK.01	MISI	-25	-25
2018-06-21	1	NY.ROSETON.SINK.02	NYSI	-100	-100
2018-06-21	18	MI.LUDINGTON.SINK.24	MISI	-100	-100
2018-06-22	13	MD.CALVERTCLIFF.SINK.14	MISI	-25	-25
2018-06-22	13	MI.LUDINGTON.SINK.14	MISI	-20	-20
2018-06-23	15	NY.ROSETON.SINK.25	NYSI	-25	-10

2018-06-24	24	NY.ROSETON.SINK.01	NYSI	-100	-100
2018-06-25	2	NY.ROSETON.SINK.02	NYSI	-100	-100
2018-06-25	13	NY.ROSETON.SINK.11	NYSI	-10	-10
2018-06-25	13	MD.CALVERTCLIFF.SINK.25	NYSI	-20	-10
2018-06-25	14	MD.CALVERTCLIFF.SINK.25	NYSI	-30	-20
2018-06-25	17	NY.ROSETON.SINK.18	NYSI	-50	-50
2018-06-27	9	NY.ROSETON.SINK.08	NYSI	-25	-25
2018-06-27	16	NY.ROSETON.SINK.17	NYSI	-50	-50
2018-06-27	17	NY.ROSETON.SINK.17	NYSI	-100	-100
2018-06-28	3	NY.ROSETON.SINK.02	NYSI	-50	-50
2018-06-28	19	MI.LUDINGTON.SINK.20	MISI	-50	-50
2018-06-28	20	MI.LUDINGTON.SINK.21	MISI	-25	-25
2018-07-01	17	NY.ROSETON.SINK.18	NYSI	-50	-25
2018-07-01	18	NY.ROSETON.SINK.18	NYSI	-50	-25
2018-07-02	14	MI.LUDINGTON.SINK.15	MISI	-25	-25
2018-07-04	1	NY.ROSETON.SINK.02	NYSI	-250	-100
2018-07-07	12	MI.LUDINGTON.SINK.13	MISI	-75	-75
2018-07-08	3	MI.LUDINGTON.SINK.04	MISI	-50	-50
2018-07-11	1	NY.ROSETON.SINK.02	NYSI	-38	-38
2018-07-11	19	MI.LUDINGTON.SINK.20	MISI	-50	-50
2018-07-11	19	MD.CALVERTCLIFF.SINK.20	MISI	-42	-42
2018-07-17	2	NY.ROSETON.SINK.03	NYSI	-34	-34
2018-07-17	13	NY.ROSETON.SINK.10	NYSI	-44	-44
2018-07-18	11	MD.CALVERTCLIFF.SINK.12	MISI	-25	-25
2018-07-19	4	NY.ROSETON.SINK.02	NYSI	-200	-200
2018-07-22	3	NY.ROSETON.SINK.02	NYSI	-50	-25
2018-07-29	6	MI.LUDINGTON.SINK.07	MISI	-63	-63
2018-08-02	1	MD.CALVERTCLIFF.SINK.02	MISI	-41	-41
2018-08-02	9	NY.ROSETON.SINK.25	NYSI	-25	-15
2018-08-02	12	MD.CALVERTCLIFF.SINK.13	MISI	-20	-10
2018-08-03	13	MD.CALVERTCLIFF.SINK.14	MISI	-25	-25
2018-08-03	14	MD.CALVERTCLIFF.SINK.15	MISI	-25	-25
2018-08-08	17	NY.ROSETON.SINK.17	NYSI	-100	-100
2018-08-09	1	NY.ROSETON.SINK.02	NYSI	-250	-150
2018-08-09	2	NY.ROSETON.SINK.02	NYSI	-84	-84
2018-08-10	2	NY.ROSETON.SINK.02	NYSI	-69	-44
2018-08-10	5	MI.LUDINGTON.SINK.06	MISI	-50	-50
2018-08-10	14	MD.CALVERTCLIFF.SINK.15	MISI	-1	-1
2018-08-10	14	MI.LUDINGTON.SINK.15	MISI	-25	-25
2018-08-10	15	MB.WHITESHELL.US.SINK.02	MBSI	-50	-50
2018-08-10	15	MD.CALVERTCLIFF.SINK.16	MISI	-25	-25

2018-08-11	3	MI.LUDINGTON.SINK.04	MISI	-50	-50
2018-08-14	10	MI.LUDINGTON.SINK.11	MISI	-50	-50
2018-08-16	10	MI.LUDINGTON.SINK.11	MISI	-25	-25
2018-08-16	13	MD.CALVERTCLIFF.SINK.14	MISI	-15	-15
2018-08-20	15	MI.LUDINGTON.SINK.16	MISI	-50	-50
2018-08-20	24	MI.LUDINGTON.SINK.01	MISI	-50	-50
2018-08-21	12	MD.CALVERTCLIFF.SINK.13	MISI	-25	-25
2018-08-21	13	MD.CALVERTCLIFF.SINK.14	MISI	-25	-25
2018-08-22	10	MI.LUDINGTON.SINK.11	MISI	-25	-15
2018-08-22	16	NY.ROSETON.SINK.25	NYSI	-50	-25
2018-08-22	17	MI.LUDINGTON.SINK.18	MISI	-25	-25
2018-08-22	19	MI.LUDINGTON.SINK.20	MISI	-15	-15
2018-08-23	4	NY.ROSETON.SINK.03	NYSI	-10	-10
2018-08-24	3	NY.ROSETON.SINK.04	NYSI	-10	-10
2018-08-24	3	NY.ROSETON.SINK.01	NYSI	-5	-2
2018-08-24	4	NY.ROSETON.SINK.04	NYSI	-10	-10
2018-08-24	4	NY.ROSETON.SINK.01	NYSI	-5	-5
2018-08-25	1	NY.ROSETON.SINK.25	NYSI	-50	-50
2018-08-25	1	MI.LUDINGTON.SINK.02	MISI	-15	-15
2018-08-25	3	NY.ROSETON.SINK.25	NYSI	-25	-15
2018-08-25	3	NY.ROSETON.SINK.02	NYSI	-15	-15
2018-08-25	4	NY.ROSETON.SINK.25	NYSI	-25	-25
2018-08-25	5	NY.ROSETON.SINK.25	NYSI	-25	-25
2018-08-25	5	MI.LUDINGTON.SINK.06	MISI	-15	-15
2018-08-25	6	NY.ROSETON.SINK.25	NYSI	-25	-18
2018-08-25	6	MI.LUDINGTON.SINK.07	MISI	-15	-15
2018-08-25	7	NY.ROSETON.SINK.25	NYSI	-50	-35
2018-08-25	7	NY.ROSETON.SINK.02	NYSI	-15	-15
2018-08-25	7	MI.LUDINGTON.SINK.08	MISI	-25	-25
2018-08-25	16	MB.WHITESHELL.US.SINK.05	MBSI	-33	-33
2018-08-25	18	MD.CALVERTCLIFF.SINK.19	MISI	-25	-25
2018-08-25	23	MI.LUDINGTON.SINK.24	MISI	-10	-10
2018-08-26	6	MI.LUDINGTON.SINK.07	MISI	-15	-15
2018-08-27	4	NY.ROSETON.SINK.25	NYSI	-25	-10
2018-08-27	5	NY.ROSETON.SINK.02	NYSI	-20	-20
2018-08-27	15	MD.CALVERTCLIFF.SINK.16	MISI	-20	-20
2018-08-27	16	NY.ROSETON.SINK.25	NYSI	-48	-10
2018-08-28	21	MI.LUDINGTON.SINK.23	MISI	-5	-5
2018-08-29	2	MI.LUDINGTON.SINK.01	MISI	-10	-10
2018-08-29	12	NY.ROSETON.SINK.10	NYSI	-10	-10
2018-08-29	15	NY.ROSETON.SINK.25	NYSI	-25	-10

2018-08-29	18	MD.CALVERTCLIFF.SINK.19	MISI	-50	-50
2018-08-30	2	NY.ROSETON.SINK.02	NYSI	-38	-38
2018-08-30	2	MI.LUDINGTON.SINK.03	MISI	-75	-75
2018-09-06	18	NY.ROSETON.SINK.18	NYSI	-50	-50
2018-09-07	4	MI.LUDINGTON.SINK.05	MISI	-75	-75
2018-09-07	16	NY.ROSETON.SINK.25	NYSI	-50	-10
2018-09-08	5	NY.ROSETON.SINK.02	NYSI	-43	-43
2018-09-08	17	MI.LUDINGTON.SINK.18	MISI	-35	-35
2018-09-08	17	MI.LUDINGTON.SINK.07	MISI	-50	-50
2018-09-08	23	MI.LUDINGTON.SINK.24	MISI	-25	-25
2018-09-08	24	MI.LUDINGTON.SINK.01	MISI	-25	-25
2018-09-09	1	MI.LUDINGTON.SINK.02	MISI	-25	-25
2018-09-09	2	NY.ROSETON.SINK.02	NYSI	-25	-25
2018-09-09	2	MI.LUDINGTON.SINK.03	MISI	-25	-25
2018-09-09	3	NY.ROSETON.SINK.02	NYSI	-25	-25
2018-09-09	4	NY.ROSETON.SINK.02	NYSI	-25	-25
2018-09-09	24	NY.ROSETON.SINK.01	NYSI	-25	-25
2018-09-09	24	MI.LUDINGTON.SINK.02	MISI	-75	-75
2018-09-10	1	MI.LUDINGTON.SINK.02	MISI	-25	-25
2018-09-10	5	NY.ROSETON.SINK.25	NYSI	-25	-15
2018-09-12	1	MI.LUDINGTON.SINK.10	MISI	-20	-20
2018-09-12	4	MI.LUDINGTON.SINK.01	MISI	-50	-50
2018-09-12	4	MI.LUDINGTON.SINK.05	MISI	-50	-50
2018-09-12	14	MI.LUDINGTON.SINK.15	MISI	-25	-25
2018-09-12	14	MD.CALVERTCLIFF.SINK.02	MISI	-25	-25
2018-09-12	18	MD.CALVERTCLIFF.SINK.19	MISI	-45	-45
2018-09-13	12	NY.ROSETON.SINK.25	NYSI	-20	-5
2018-09-13	16	MI.LUDINGTON.SINK.17	MISI	-15	-15
2018-09-19	1	NY.ROSETON.SINK.25	NYSI	-50	-35
2018-09-19	1	NY.ROSETON.SINK.02	NYSI	-57	-7
2018-09-19	1	MI.LUDINGTON.SINK.27	MISI	-10	-10
2018-09-19	4	NY.ROSETON.SINK.02	NYSI	-75	-50
2018-09-19	13	MD.CALVERTCLIFF.SINK.14	MISI	-50	-50
2018-09-19	16	NY.ROSETON.SINK.25	NYSI	-150	-75
2018-09-19	16	MD.CALVERTCLIFF.SINK.17	MISI	-25	-25
2018-09-20	3	MB.WHITESHELL.US.SINK.01	MBSI	-50	-50
2018-09-20	3	MI.LUDINGTON.SINK.04	MISI	-100	-100
2018-09-20	24	MB.WHITESHELL.US.SINK.01	MBSI	-4	-4
2018-09-21	3	NY.ROSETON.SINK.02	NYSI	-50	-50
2018-09-21	16	NY.ROSETON.SINK.25	NYSI	-70	-20
2018-09-21	22	MB.WHITESHELL.US.SINK.04	MBSI	-41	-41

2018-09-22	24	MI.LUDINGTON.SINK.01	MISI	-20	-20
2018-09-24	1	MB.WHITESHELL.US.SINK.01	MBSI	-50	-9
2018-09-24	2	NY.ROSETON.SINK.02	NYSI	-25	-25
2018-09-24	2	MI.LUDINGTON.SINK.03	MISI	-25	-25
2018-09-24	19	NY.ROSETON.SINK.25	NYSI	-79	-54
2018-09-24	22	MB.WHITESHELL.US.SINK.01	MBSI	-25	-25
2018-09-25	7	NY.ROSETON.SINK.25	NYSI	-50	-15
2018-09-25	20	NY.ROSETON.SINK.25	NYSI	-25	-25
2018-09-26	11	MI.LUDINGTON.SINK.01	MISI	-25	-25
2018-09-26	18	MI.LUDINGTON.SINK.01	MISI	-25	-25
2018-09-26	24	MB.WHITESHELL.US.SINK.01	MBSI	-33	-33
2018-09-26	24	NY.ROSETON.SINK.01	NYSI	-50	-50
2018-09-27	15	NY.ROSETON.SINK.15	NYSI	-25	-25
2018-09-27	15	NY.ROSETON.SINK.25	NYSI	-100	-25
2018-09-27	22	MI.LUDINGTON.SINK.23	MISI	-14	-14
2018-09-27	23	MI.LUDINGTON.SINK.24	MISI	-50	-50
2018-09-28	10	NY.ROSETON.SINK.25	NYSI	-50	-15
2018-09-28	13	MB.WHITESHELL.US.SINK.01	MBSI	-19	-19
2018-09-28	13	NY.ROSETON.SINK.10	NYSI	-15	-15
2018-09-28	24	MI.LUDINGTON.SINK.01	MISI	-50	-50
2018-09-29	10	MB.WHITESHELL.US.SINK.01	MBSI	-50	-50
2018-09-29	12	MB.WHITESHELL.US.SINK.01	MBSI	-33	-33
2018-09-29	13	MB.WHITESHELL.US.SINK.01	MBSI	-33	-33
2018-09-29	16	MI.LUDINGTON.SINK.17	MISI	-25	-25
2018-09-29	19	MD.CALVERTCLIFF.SINK.20	MISI	-25	-25
2018-09-30	5	MB.WHITESHELL.US.SINK.01	MBSI	-50	-50
2018-09-30	9	MI.LUDINGTON.SINK.10	MISI	-25	-25
2018-09-30	10	MI.LUDINGTON.SINK.11	MISI	-25	-25
2018-09-30	11	MI.LUDINGTON.SINK.12	MISI	-19	-19
2018-09-30	14	MD.CALVERTCLIFF.SINK.15	MISI	-25	-25
2018-09-30	24	MB.WHITESHELL.US.SINK.01	MBSI	-33	-33
2018-10-01	2	MI.LUDINGTON.SINK.03	MISI	-25	-25
2018-10-01	3	MI.LUDINGTON.SINK.04	MISI	-25	-25
2018-10-01	3	MB.WHITESHELL.US.SINK.01	MBSI	-33	-33
2018-10-01	4	MI.LUDINGTON.SINK.05	MISI	-3	-3
2018-10-01	11	MD.CALVERTCLIFF.SINK.01	MISI	-25	-25
2018-10-01	12	NY.ROSETON.SINK.10	NYSI	-25	-25
2018-10-01	24	MI.LUDINGTON.SINK.01	MISI	-25	-25
2018-10-02	1	MI.LUDINGTON.SINK.02	MISI	-25	-25
2018-10-02	10	NY.ROSETON.SINK.10	NYSI	-25	-25
2018-10-02	12	MB.WHITESHELL.US.SINK.01	MBSI	-1	-1

2018-10-02	17	MI.LUDINGTON.SINK.18	MISI	-25	-25
2018-10-02	18	MI.LUDINGTON.SINK.19	MISI	-25	-25
2018-10-03	1	MI.LUDINGTON.SINK.02	MISI	-39	-39
2018-10-03	12	MB.WHITESHELL.US.SINK.01	MBSI	-50	-40
2018-10-04	9	MB.WHITESHELL.US.SINK.01	MBSI	-33	-33
2018-10-04	10	MB.WHITESHELL.US.SINK.01	MBSI	-33	-33
2018-10-04	11	MB.WHITESHELL.US.SINK.01	MBSI	-33	-33
2018-10-04	12	MB.WHITESHELL.US.SINK.01	MBSI	-33	-33
2018-10-04	13	MI.LUDINGTON.SINK.14	MISI	-20	-20
2018-10-05	11	NY.ROSETON.SINK.06	NYSI	-25	-15
2018-10-05	19	MB.WHITESHELL.US.SINK.01	MBSI	-33	-33
2018-10-05	23	NY.ROSETON.SINK.01	NYSI	-84	-34
2018-10-06	1	MD.CALVERTCLIFF.SINK.01	MISI	-50	-50
2018-10-06	3	MB.WHITESHELL.CAN.SOURCE.01	MBSI	1	1
2018-10-06	9	NY.ROSETON.SINK.25	NYSI	-50	-25
2018-10-06	10	NY.ROSETON.SINK.25	NYSI	-15	-15
2018-10-06	11	NY.ROSETON.SINK.25	NYSI	-50	-50
2018-10-06	14	NY.ROSETON.SINK.25	NYSI	-50	-50
2018-10-06	22	NY.ROSETON.SINK.25	NYSI	-50	-50
2018-10-07	7	MI.LUDINGTON.SINK.02	MISI	-25	-25
2018-10-07	11	MI.LUDINGTON.SINK.03	MISI	-25	-25
2018-10-07	12	NY.ROSETON.SINK.03	NYSI	-15	-15
2018-10-07	12	MI.LUDINGTON.SINK.03	MISI	-25	-25
2018-10-07	24	MB.WHITESHELL.CAN.SOURCE.01	MBSI	19	19
2018-10-07	24	NY.ROSETON.SINK.02	NYSI	-25	-25
2018-10-08	3	MI.LUDINGTON.SINK.02	MISI	-25	-25
2018-10-08	4	NY.ROSETON.SINK.02	NYSI	-25	-25
2018-10-08	4	MI.LUDINGTON.SINK.02	MISI	-25	-25
2018-10-08	5	MI.LUDINGTON.SINK.02	MISI	-25	-25
2018-10-08	8	MB.WHITESHELL.US.SINK.01	MBSI	-50	-50
2018-10-08	9	NY.ROSETON.SINK.10	NYSI	-25	-25
2018-10-08	9	MB.WHITESHELL.US.SINK.01	MBSI	-50	-33
2018-10-08	10	MB.WHITESHELL.US.SINK.01	MBSI	-50	-50
2018-10-08	12	MB.WHITESHELL.US.SINK.01	MBSI	-50	-50
2018-10-08	16	NY.ROSETON.SINK.10	NYSI	-5	-5
2018-10-08	17	NY.ROSETON.SINK.10	NYSI	-25	-10
2018-10-08	22	MB.WHITESHELL.CAN.SOURCE.01	MBSI	19	19
2018-10-09	1	MD.CALVERTCLIFF.SINK.02	MISI	-25	-25
2018-10-09	3	MI.LUDINGTON.SINK.02	MISI	-25	-25
2018-10-09	22	NY.ROSETON.SINK.01	NYSI	-50	-50
2018-10-10	1	NY.ROSETON.SINK.01	NYSI	-250	-250

2018-10-10	9	NY.ROSETON.SINK.10	NYSI	-25	-25
2018-10-10	13	NY.ROSETON.SINK.25	NYSI	-25	-10
2018-10-10	13	MB.WHITESHELL.US.SINK.01	MBSI	-66	-66
2018-10-10	14	NY.ROSETON.SINK.25	NYSI	-25	-15
2018-10-10	15	NY.ROSETON.SINK.25	NYSI	-6	-6
2018-10-10	21	MB.WHITESHELL.US.SINK.01	MBSI	-33	-33
2018-10-10	23	NY.ROSETON.SINK.01	NYSI	-50	-50
2018-10-11	9	MB.WHITESHELL.US.SINK.01	MBSI	-33	-33
2018-10-11	9	MD.CALVERTCLIFF.SINK.02	MISI	-25	-25
2018-10-11	14	NY.ROSETON.SINK.25	NYSI	-25	-15
2018-10-11	14	NY.ROSETON.SINK.02	NYSI	-25	-25
2018-10-11	14	MD.CALVERTCLIFF.SINK.02	MISI	-25	-25
2018-10-11	15	NY.ROSETON.SINK.25	NYSI	-25	-15
2018-10-11	15	NY.ROSETON.SINK.02	NYSI	-20	-20
2018-10-11	15	MD.CALVERTCLIFF.SINK.02	MISI	-25	-25
2018-10-11	16	MD.CALVERTCLIFF.SINK.02	MISI	-25	-25
2018-10-12	11	MB.WHITESHELL.US.SINK.01	MBSI	-66	-4
2018-10-12	12	MB.WHITESHELL.US.SINK.01	MBSI	-66	-33
2018-10-12	12	NY.ROSETON.SINK.10	NYSI	-25	-25
2018-10-12	13	MB.WHITESHELL.US.SINK.01	MBSI	-66	-66
2018-10-12	16	NY.ROSETON.SINK.03	NYSI	-20	-20
2018-10-13	13	MB.WHITESHELL.US.SINK.01	MBSI	-45	-45
2018-10-13	24	MB.WHITESHELL.US.SINK.01	MBSI	-9	-9
2018-10-14	1	MB.WHITESHELL.US.SINK.01	MBSI	-9	-9
2018-10-14	2	NY.ROSETON.SINK.02	NYSI	-50	-50
2018-10-14	3	MB.WHITESHELL.US.SINK.01	MBSI	-9	-9
2018-10-15	9	MB.WHITESHELL.US.SINK.01	MBSI	-33	-33
2018-10-15	11	MI.LUDINGTON.SINK.06	MISI	-25	-25
2018-10-15	12	MB.WHITESHELL.US.SINK.01	MBSI	-33	-33
2018-10-15	14	NY.ROSETON.SINK.06	NYSI	-25	-25
2018-10-16	11	NY.ROSETON.SINK.06	NYSI	-50	-50
2018-10-16	12	MB.WHITESHELL.US.SINK.01	MBSI	-33	-33
2018-10-16	13	NY.ROSETON.SINK.06	NYSI	-25	-25
2018-10-16	14	NY.ROSETON.SINK.25	NYSI	-50	-20
2018-10-16	20	NY.ROSETON.SINK.25	NYSI	-25	-10
2018-10-16	20	NY.ROSETON.SINK.02	NYSI	-50	-50
2018-10-16	21	NY.ROSETON.SINK.25	NYSI	-47	-10
2018-10-16	21	MD.CALVERTCLIFF.SINK.02	MISI	-25	-25
2018-10-17	11	NY.ROSETON.SINK.06	NYSI	-25	-25
2018-10-17	13	NY.ROSETON.SINK.25	NYSI	-50	-15
2018-10-17	15	NY.ROSETON.SINK.06	NYSI	-25	-25

2018-10-17	16	NY.ROSETON.SINK.25	NYSI	-50	-15
2018-10-17	19	MB.WHITESHELL.CAN.SOURCE.01	MBSI	6	1
2018-10-17	23	NY.ROSETON.SINK.01	NYSI	-6	-6
2018-10-18	11	NY.ROSETON.SINK.03	NYSI	-30	-15
2018-10-18	11	NY.ROSETON.SINK.25	NYSI	-25	-10
2018-10-18	12	NY.ROSETON.SINK.25	NYSI	-25	-25
2018-10-19	9	MB.WHITESHELL.US.SINK.01	MBSI	-50	-50
2018-10-19	12	MB.WHITESHELL.US.SINK.01	MBSI	-50	-50
2018-10-19	12	NY.ROSETON.SINK.06	NYSI	-46	-16
2018-10-19	14	MB.WHITESHELL.US.SINK.02	MBSI	-50	-50
2018-10-19	14	NY.ROSETON.SINK.02	NYSI	-50	-50
2018-10-19	15	MB.WHITESHELL.US.SINK.01	MBSI	-50	-50
2018-10-19	17	NY.ROSETON.SINK.02	NYSI	-50	-30
2018-10-19	20	NY.ROSETON.SINK.01	NYSI	-25	-25
2018-10-20	9	NY.ROSETON.SINK.25	NYSI	-25	-15
2018-10-20	13	NY.ROSETON.SINK.14	NYSI	-20	-20
2018-10-20	14	NY.ROSETON.SINK.14	NYSI	-20	-10
2018-10-20	21	MB.WHITESHELL.US.SINK.01	MBSI	-50	-50
2018-10-20	21	NY.ROSETON.SINK.02	NYSI	-10	-10
2018-10-20	22	MI.LUDINGTON.SINK.02	MISI	-25	-25
2018-10-21	2	NY.ROSETON.SINK.25	NYSI	-19	-19
2018-10-21	4	MB.WHITESHELL.US.SINK.01	MBSI	-43	-43
2018-10-21	5	MB.WHITESHELL.US.SINK.01	MBSI	-43	-43
2018-10-21	6	MB.WHITESHELL.US.SINK.01	MBSI	-33	-33
2018-10-21	12	MD.CALVERTCLIFF.SINK.03	MISI	-25	-25
2018-10-21	14	NY.ROSETON.SINK.25	NYSI	-25	-5
2018-10-21	14	NY.ROSETON.SINK.03	NYSI	-20	-13
2018-10-21	15	NY.ROSETON.SINK.03	NYSI	-15	-15
2018-10-21	16	MB.WHITESHELL.US.SINK.01	MBSI	-33	-33
2018-10-21	20	MI.LUDINGTON.SINK.03	MISI	-25	-25
2018-10-21	23	MB.WHITESHELL.US.SINK.01	MBSI	-50	-50
2018-10-21	24	MB.WHITESHELL.US.SINK.01	MBSI	-50	-50
2018-10-22	1	MB.WHITESHELL.US.SINK.01	MBSI	-50	-50
2018-10-22	2	MB.WHITESHELL.US.SINK.01	MBSI	-50	-50
2018-10-22	3	MB.WHITESHELL.US.SINK.01	MBSI	-15	-15
2018-10-22	11	NY.ROSETON.SINK.10	NYSI	-50	-25
2018-10-22	14	MB.WHITESHELL.US.SINK.01	MBSI	-66	-66
2018-10-22	22	MB.WHITESHELL.US.SINK.01	MBSI	-50	-50
2018-10-23	1	MB.WHITESHELL.US.SINK.01	MBSI	-50	-50
2018-10-23	2	MB.WHITESHELL.US.SINK.01	MBSI	-50	-50
2018-10-23	5	MB.WHITESHELL.US.SINK.01	MBSI	-50	-50

2018-10-23	6	MD.CALVERTCLIFF.SINK.02	MISI	-25	-25
2018-10-23	14	MB.WHITESHELL.US.SINK.01	MBSI	-40	-40
2018-10-24	6	MD.CALVERTCLIFF.SINK.01	MISI	-46	-46
2018-10-24	12	MB.WHITESHELL.US.SINK.01	MBSI	-36	-36
2018-10-27	10	NY.ROSETON.SINK.02	NYSI	-46	-46
2018-10-27	12	MB.WHITESHELL.US.SINK.01	MBSI	-50	-50
2018-10-27	13	MB.WHITESHELL.US.SINK.01	MBSI	-50	-50
2018-10-27	19	NY.ROSETON.SINK.02	NYSI	-25	-25
2018-10-27	22	MI.LUDINGTON.SINK.03	MISI	-15	-15
2018-10-29	5	MD.CALVERTCLIFF.SINK.03	MISI	-25	-25
2018-10-30	23	MI.LUDINGTON.SINK.01	MISI	-50	-50
2018-10-31	13	MB.WHITESHELL.US.SINK.01	MBSI	-40	-40
2018-10-31	20	MD.CALVERTCLIFF.SINK.01	MISI	-25	-25
2018-11-01	12	MD.CALVERTCLIFF.SINK.06	MISI	-25	-25
2018-11-01	22	MI.LUDINGTON.SINK.01	MISI	-50	-50
2018-11-02	21	MD.CALVERTCLIFF.SINK.03	MISI	-20	-20
2018-11-05	10	MI.LUDINGTON.SINK.06	MISI	-25	-25
2018-11-05	11	NY.ROSETON.SINK.06	NYSI	-25	-25
2018-11-05	12	NY.ROSETON.SINK.25	NYSI	-8	-4
2018-11-05	19	NY.ROSETON.SINK.01	NYSI	-25	-25
2018-11-06	2	MB.WHITESHELL.US.SINK.01	MBSI	-48	-48
2018-11-06	13	NY.ROSETON.SINK.09	NYSI	-25	-25
2018-11-06	13	MI.LUDINGTON.SINK.13	MISI	-10	-10
2018-11-06	14	NY.ROSETON.SINK.09	NYSI	-25	-25
2018-11-06	14	MI.LUDINGTON.SINK.14	MISI	-10	-10
2018-11-06	16	NY.ROSETON.SINK.09	NYSI	-25	-25
2018-11-06	16	MB.WHITESHELL.US.SINK.05	MBSI	-50	-50
2018-11-06	18	MD.CALVERTCLIFF.SINK.01	MISI	-25	-25
2018-11-06	20	NY.ROSETON.SINK.01	NYSI	-25	-25
2018-11-06	21	MB.WHITESHELL.US.SINK.01	MBSI	-50	-9
2018-11-07	10	NY.ROSETON.SINK.06	NYSI	-25	-25
2018-11-07	11	NY.ROSETON.SINK.06	NYSI	-25	-25
2018-11-07	13	NY.ROSETON.SINK.06	NYSI	-25	-25
2018-11-07	15	NY.ROSETON.SINK.06	NYSI	-25	-25
2018-11-07	15	MD.CALVERTCLIFF.SINK.06	MISI	-25	-25
2018-11-07	24	MB.WHITESHELL.CAN.SOURCE.01	MBSI	12	1
2018-11-08	15	MI.LUDINGTON.SINK.03	MISI	-15	-15
2018-11-09	3	MB.WHITESHELL.US.SINK.05	MBSI	-31	-2
2018-11-09	3	MI.LUDINGTON.SINK.06	MISI	-50	-50
2018-11-09	6	MB.WHITESHELL.US.SINK.05	MBSI	-31	-31
2018-11-09	7	MB.WHITESHELL.US.SINK.05	MBSI	-28	-4

2018-11-10	4	MB.WHITESHELL.US.SINK.05	MBSI	-50	-50
2018-11-10	5	MB.WHITESHELL.US.SINK.05	MBSI	-33	-33
2018-11-10	16	MI.LUDINGTON.SINK.03	MISI	-25	-25
2018-11-10	17	MI.LUDINGTON.SINK.03	MISI	-20	-20
2018-11-11	7	MB.WHITESHELL.US.SINK.02	MBSI	-50	-50
2018-11-11	8	NY.ROSETON.SINK.02	NYSI	-50	-50
2018-11-11	9	MB.WHITESHELL.US.SINK.02	MBSI	-50	-50
2018-11-11	10	NY.ROSETON.SINK.03	NYSI	-15	-15
2018-11-11	10	MD.CALVERTCLIFF.SINK.03	MISI	-35	-35
2018-11-11	14	NY.ROSETON.SINK.03	NYSI	-20	-20
2018-11-11	15	MB.WHITESHELL.US.SINK.01	MBSI	-33	-33
2018-11-11	24	MI.LUDINGTON.SINK.02	MISI	-50	-50
2018-11-12	3	MD.CALVERTCLIFF.SINK.02	MISI	-50	-50
2018-11-12	4	MB.WHITESHELL.US.SINK.02	MBSI	-50	-50
2018-11-12	4	MD.CALVERTCLIFF.SINK.02	MISI	-50	-50
2018-11-13	3	MB.WHITESHELL.US.SINK.02	MBSI	-50	-50
2018-11-13	5	MI.LUDINGTON.SINK.05	MISI	-25	-25
2018-11-13	12	MI.LUDINGTON.SINK.12	MISI	-10	-10
2018-11-13	23	NY.ROSETON.SINK.01	NYSI	-25	-25
2018-11-13	24	NY.ROSETON.SINK.01	NYSI	-100	-50
2018-11-14	3	MB.WHITESHELL.US.SINK.01	MBSI	-50	-50
2018-11-16	10	MD.CALVERTCLIFF.SINK.02	MISI	-25	-25
2018-11-16	10	MI.LUDINGTON.SINK.02	MISI	-25	-25
2018-11-16	11	MI.LUDINGTON.SINK.02	MISI	-25	-25
2018-11-16	12	MD.CALVERTCLIFF.SINK.02	MISI	-25	-25
2018-11-16	23	MB.WHITESHELL.US.SINK.01	MBSI	-33	-33
2018-11-17	2	NY.ROSETON.SINK.03	NYSI	-50	-30
2018-11-17	4	NY.ROSETON.SINK.03	NYSI	-10	-10
2018-11-17	5	NY.ROSETON.SINK.03	NYSI	-10	-10
2018-11-17	6	MB.WHITESHELL.US.SINK.01	MBSI	-50	-50
2018-11-17	6	NY.ROSETON.SINK.03	NYSI	-10	-10
2018-11-17	9	NY.ROSETON.SINK.03	NYSI	-15	-15
2018-11-17	13	NY.ROSETON.SINK.06	NYSI	-25	-25
2018-11-21	6	MB.WHITESHELL.US.SINK.01	MBSI	-50	-21
2018-11-23	3	MB.WHITESHELL.US.SINK.01	MBSI	-66	-66
2018-11-23	5	NY.ROSETON.SINK.01	NYSI	-100	-25
2018-11-24	12	MD.CALVERTCLIFF.SINK.06	MISI	-15	-15
2018-11-24	14	MI.LUDINGTON.SINK.06	MISI	-50	-50
2018-11-24	15	NY.ROSETON.SINK.25	NYSI	-25	-10
2018-11-25	1	NY.ROSETON.SINK.02	NYSI	-53	-53
2018-11-25	3	NY.ROSETON.SINK.05	NYSI	-4	-4

2018-11-25	24	NY.ROSETON.SINK.25	NYSI	-25	-25
2018-11-25	24	NY.ROSETON.SINK.02	NYSI	-28	-28
2018-11-26	2	MB.WHITESHELL.US.SINK.02	MBSI	-14	-14
2018-11-26	9	MI.LUDINGTON.SINK.02	MISI	-42	-42
2018-11-26	23	MB.WHITESHELL.US.SINK.02	MBSI	-50	-50
2018-11-27	2	MB.WHITESHELL.US.SINK.02	MBSI	-12	-12
2018-11-27	2	MI.LUDINGTON.SINK.02	MISI	-50	-50
2018-11-27	7	MI.LUDINGTON.SINK.02	MISI	-39	-1
2018-11-27	12	MI.LUDINGTON.SINK.12	MISI	-25	-10
2018-11-28	7	MI.LUDINGTON.SINK.01	MISI	-30	-1
2018-11-28	13	NY.ROSETON.SINK.06	NYSI	-50	-25
2018-11-28	17	NY.ROSETON.SINK.06	NYSI	-25	-25
2018-11-28	21	NY.ROSETON.SINK.01	NYSI	-25	-25
2018-11-29	19	MD.CALVERTCLIFF.SINK.01	MISI	-25	-25
2018-12-01	2	MD.CALVERTCLIFF.SINK.01	MISI	-50	-50
2018-12-02	1	MB.WHITESHELL.US.SINK.01	MBSI	-66	-66
2018-12-02	1	MD.CALVERTCLIFF.SINK.03	MISI	-35	-35
2018-12-02	2	MB.WHITESHELL.US.SINK.01	MBSI	-66	-66
2018-12-02	4	MB.WHITESHELL.US.SINK.01	MBSI	-49	-49
2018-12-02	4	MB.WHITESHELL.US.SINK.02	MBSI	-20	-20
2018-12-02	5	MB.WHITESHELL.US.SINK.01	MBSI	-49	-49
2018-12-02	6	MB.WHITESHELL.US.SINK.01	MBSI	-49	-49
2018-12-02	15	MB.WHITESHELL.US.SINK.02	MBSI	-60	-60
2018-12-02	23	NY.ROSETON.SINK.03	NYSI	-20	-20
2018-12-03	3	MD.CALVERTCLIFF.SINK.03	MISI	-15	-15
2018-12-03	24	MB.WHITESHELL.US.SINK.02	MBSI	-50	-50
2018-12-04	2	MB.WHITESHELL.US.SINK.02	MBSI	-33	-4
2018-12-05	2	NY.ROSETON.SINK.02	NYSI	-10	-10
2018-12-05	3	MB.WHITESHELL.US.SINK.02	MBSI	-54	-54
2018-12-05	4	MB.WHITESHELL.US.SINK.02	MBSI	-9	-9
2018-12-05	10	MD.CALVERTCLIFF.SINK.06	MISI	-25	-25
2018-12-06	10	MD.CALVERTCLIFF.SINK.03	MISI	-30	-30
2018-12-06	15	MD.CALVERTCLIFF.SINK.03	MISI	-25	-25
2018-12-06	15	MI.LUDINGTON.SINK.03	MISI	-20	-20
2018-12-06	19	MD.CALVERTCLIFF.SINK.03	MISI	-30	-30
2018-12-06	20	MD.CALVERTCLIFF.SINK.03	MISI	-20	-20
2018-12-07	2	MB.WHITESHELL.US.SINK.01	MBSI	-50	-50
2018-12-08	1	MD.CALVERTCLIFF.SINK.03	MISI	-25	-25
2018-12-08	5	NY.ROSETON.SINK.25	NYSI	-30	-10
2018-12-08	5	NY.ROSETON.SINK.03	NYSI	-50	-50
2018-12-08	6	NY.ROSETON.SINK.25	NYSI	-30	-30

2018-12-08	6	NY.ROSETON.SINK.03	NYSI	-17	-17
2018-12-08	6	MD.CALVERTCLIFF.SINK.03	MISI	-30	-30
2018-12-09	4	MI.LUDINGTON.SINK.03	MISI	-25	-25
2018-12-09	12	MD.CALVERTCLIFF.SINK.01	MISI	-25	-25
2018-12-13	4	MD.CALVERTCLIFF.SINK.01	MISI	-50	-50
2018-12-13	5	MD.CALVERTCLIFF.SINK.01	MISI	-50	-50
2018-12-15	3	MI.LUDINGTON.SINK.03	MISI	-20	-20
2018-12-15	4	MI.LUDINGTON.SINK.03	MISI	-25	-25
2018-12-15	5	MD.CALVERTCLIFF.SINK.03	MISI	-25	-25
2018-12-16	2	MD.CALVERTCLIFF.SINK.24	MISI	-25	-25
2018-12-16	3	MD.CALVERTCLIFF.SINK.03	MISI	-25	-25
2018-12-16	4	MI.LUDINGTON.SINK.03	MISI	-25	-25
2018-12-16	5	MD.CALVERTCLIFF.SINK.03	MISI	-30	-30
2018-12-16	6	MI.LUDINGTON.SINK.03	MISI	-35	-35
2018-12-16	11	MD.CALVERTCLIFF.SINK.06	MISI	-25	-25
2018-12-17	6	NY.ROSETON.SINK.02	NYSI	-100	-1
2018-12-17	19	MD.CALVERTCLIFF.SINK.01	MISI	-50	-50
2018-12-18	2	NY.ROSETON.SINK.02	NYSI	-50	-50
2018-12-19	2	NY.ROSETON.SINK.01	NYSI	-150	-50
2018-12-19	10	MI.LUDINGTON.SINK.06	MISI	-25	-25
2018-12-20	6	NY.ROSETON.SINK.07	NYSI	-25	-25
2018-12-22	3	MN.INTFALLS.US.SINK.03	MNSI	-35	-35
2018-12-22	4	MN.INTFALLS.US.SINK.03	MNSI	-30	-30
2018-12-24	14	MB.WHITESHELL.US.SINK.01	MBSI	-75	-75
2018-12-27	4	MD.CALVERTCLIFF.SINK.01	MISI	-100	-100
2018-12-27	24	NY.ROSETON.SINK.01	NYSI	-25	-25
2018-12-27	24	MB.WHITESHELL.US.SINK.01	MBSI	-50	-50
2018-12-28	5	MB.WHITESHELL.US.SINK.01	MBSI	-50	-50
2018-12-28	20	MB.WHITESHELL.US.SINK.02	MBSI	-50	-50
2018-12-28	23	NY.ROSETON.SINK.02	NYSI	-100	-100
2018-12-30	3	NY.ROSETON.SINK.02	NYSI	-45	-45
2018-12-30	3	MI.LUDINGTON.SINK.02	MISI	-50	-50
2018-12-31	4	MB.WHITESHELL.US.SINK.01	MBSI	-66	-4
2018-12-31	13	MI.LUDINGTON.SINK.01	MISI	-75	-75
2019-01-01	2	MB.WHITESHELL.US.SINK.01	MBSI	-50	-50
2019-01-01	9	MI.LUDINGTON.SINK.03	MISI	-1	-1
2019-01-03	1	MN.INTFALLS.US.SINK.01	MNSI	-25	-25
2019-01-04	1	MB.WHITESHELL.US.SINK.01	MBSI	-75	-17
2019-01-04	13	NY.ROSETON.SINK.06	NYSI	-25	-25
2019-01-06	1	NY.ROSETON.SINK.02	NYSI	-90	-40
2019-01-06	7	MB.WHITESHELL.US.SINK.02	MBSI	-41	-41

2019-01-07	13	NY.ROSETON.SINK.25	NYSI	-50	-25
2019-01-08	3	NY.ROSETON.SINK.03	NYSI	-100	-100
2019-01-09	2	MN.INTFALLS.US.SINK.02	MNSI	-5	-5
2019-01-09	3	NY.ROSETON.SINK.02	NYSI	-100	-50
2019-01-11	4	MD.CALVERTCLIFF.SINK.01	MISI	-50	-50
2019-01-11	6	NY.ROSETON.SINK.25	NYSI	-50	-50
2019-01-12	24	NY.ROSETON.SINK.04	NYSI	-15	-15
2019-01-12	24	NY.ROSETON.SINK.02	NYSI	-34	-34
2019-01-13	1	NY.ROSETON.SINK.25	NYSI	-25	-25
2019-01-13	5	MB.WHITESHELL.US.SINK.02	MBSI	-75	-75
2019-01-16	4	NY.ROSETON.SINK.02	NYSI	-50	-50
2019-01-19	7	NY.ROSETON.SINK.04	NYSI	-30	-30
2019-01-19	16	NY.ROSETON.SINK.25	NYSI	-25	-13
2019-01-19	20	NY.ROSETON.SINK.25	NYSI	-25	-5
2019-01-21	14	MI.LUDINGTON.SINK.06	MISI	-15	-15
2019-01-22	14	NY.ROSETON.SINK.01	NYSI	-50	-50
2019-01-23	12	NY.ROSETON.SINK.25	NYSI	-50	-20
2019-01-23	13	MI.LUDINGTON.SINK.06	MISI	-25	-25
2019-01-23	14	NY.ROSETON.SINK.25	NYSI	-25	-15
2019-01-30	13	MI.LUDINGTON.SINK.06	MISI	-50	-25
2019-01-30	14	MI.LUDINGTON.SINK.06	MISI	-25	-25
2019-01-31	13	MD.CALVERTCLIFF.SINK.02	MISI	-100	-100
2019-02-04	3	NY.ROSETON.SINK.25	NYSI	-17	-17
2019-02-07	23	MB.WHITESHELL.US.SINK.01	MBSI	-68	-68
2019-02-08	6	MN.INTFALLS.US.SINK.01	MNSI	-25	-25
2019-02-08	11	NY.ROSETON.SINK.06	NYSI	-25	-25
2019-02-09	4	MB.WHITESHELL.US.SINK.03	MBSI	-68	-68
2019-02-12	6	NY.ROSETON.SINK.02	NYSI	-150	-25
2019-02-13	8	MI.LUDINGTON.SINK.04	MISI	-40	-40
2019-02-13	11	MI.LUDINGTON.SINK.05	MISI	-10	-10
2019-02-13	11	MI.LUDINGTON.SINK.01	MISI	-10	-10
2019-02-15	5	MI.LUDINGTON.SINK.01	MISI	-100	-100
2019-03-10	8	MD.CALVERTCLIFF.SINK.03	MISI	-30	-30
2019-03-13	7	MD.CALVERTCLIFF.SINK.04	MISI	-50	-50
2019-03-15	3	MN.INTFALLS.US.SINK.01	MNSI	-44	-44
2019-03-22	9	NY.ROSETON.SINK.25	NYSI	-50	-25
2019-03-23	12	MN.INTFALLS.US.SINK.01	MNSI	-25	-25
2019-04-01	11	MN.INTFALLS.US.SINK.01	MNSI	-25	-25
2019-04-09	13	NY.ROSETON.SINK.25	NYSI	-50	-50
2019-04-10	19	MD.CALVERTCLIFF.SINK.04	NYSI	-150	-150
2019-04-12	12	MN.INTFALLS.US.SINK.01	MNSI	-25	-25

2019-04-12	12	MI.LUDINGTON.SINK.01	MISI	-24	-24
2019-04-12	17	MB.WHITESHELL.US.SINK.01	MBSI	-50	-50
2019-04-14	23	MB.WHITESHELL.US.SINK.01	MBSI	-66	-66
2019-04-18	1	NY.ROSETON.SINK.03	NYSI	-35	-35
2019-04-18	7	MD.CALVERTCLIFF.SINK.03	NYSI	-35	-35
2019-04-19	6	MB.WHITESHELL.US.SINK.03	MBSI	-50	-50
2019-04-20	16	MB.WHITESHELL.US.SINK.05	MBSI	-15	-4
2019-04-23	6	MD.CALVERTCLIFF.SINK.04	NYSI	-85	-5
2019-04-25	16	MD.CALVERTCLIFF.SINK.03	NYSI	-30	-30
2019-04-26	6	NY.ROSETON.SINK.25	NYSI	-25	-25
2019-04-30	1	MB.WHITESHELL.US.SINK.02	MBSI	-50	-50
2019-05-01	12	NY.ROSETON.SINK.25	NYSI	-50	-25
2019-05-06	11	NY.ROSETON.SINK.03	NYSI	-30	-30
2019-05-08	2	NY.ROSETON.SINK.03	NYSI	-30	-30
2019-05-08	4	NY.ROSETON.SINK.03	NYSI	-30	-30
2019-05-08	12	NY.ROSETON.SINK.02	NYSI	-145	-100
2019-05-09	8	NY.ROSETON.SINK.25	NYSI	-50	-20
2019-05-09	10	NY.ROSETON.SINK.25	NYSI	-100	-75
2019-05-10	13	NY.ROSETON.SINK.04	NYSI	-125	-125
2019-05-12	15	NY.ROSETON.SINK.25	NYSI	-25	-25
2019-05-13	24	NY.ROSETON.SINK.06	NYSI	-13	-13
2019-05-13	24	NY.ROSETON.SINK.24	NYSI	-50	-25
2019-05-15	23	NY.ROSETON.SINK.25	NYSI	-50	-50
2019-05-15	23	NY.ROSETON.SINK.05	NYSI	-25	-25
2019-05-18	7	MN.INTFALLS.US.SINK.03	MNSI	-2	-2
2019-05-18	24	MD.CALVERTCLIFF.SINK.24	NYSI	-25	-7
2019-05-19	2	MN.INTFALLS.US.SINK.03	MNSI	-4	-4
2019-05-20	9	NY.ROSETON.SINK.04	NYSI	-50	-50
2019-05-20	10	NY.ROSETON.SINK.04	NYSI	-50	-50
2019-05-20	12	NY.ROSETON.SINK.04	NYSI	-50	-50
2019-05-20	16	NY.ROSETON.SINK.04	NYSI	-25	-25
2019-05-23	15	NY.ROSETON.SINK.25	NYSI	-100	-50
2019-05-23	15	NY.ROSETON.SINK.05	NYSI	-25	-25
2019-05-23	16	NY.ROSETON.SINK.25	NYSI	-100	-100
2019-05-23	20	MN.INTFALLS.US.SINK.05	MNSI	-5	-5
2019-05-23	20	MD.CALVERTCLIFF.SINK.05	MISI	-12	-12
2019-05-24	6	MI.LUDINGTON.SINK.01	MISI	-50	-50
2019-05-25	2	NY.ROSETON.SINK.01	NYSI	-50	-50
2019-05-25	3	NY.ROSETON.SINK.25	NYSI	-47	-47
2019-05-26	1	NY.ROSETON.SINK.25	NYSI	-50	-50
2019-05-26	15	MN.INTFALLS.US.SINK.03	MNSI	-6	-6

2019-05-27	1	NY.ROSETON.SINK.25	NYSI	-50	-50
2019-05-27	24	NY.ROSETON.SINK.03	NYSI	-45	-20
2019-05-28	4	NY.ROSETON.SINK.25	NYSI	-50	-15
2019-05-28	4	NY.ROSETON.SINK.03	NYSI	-25	-25
2019-05-28	10	MB.WHITESHELL.US.SINK.02	MBSI	-50	-50
2019-05-28	14	NY.ROSETON.SINK.02	NYSI	-50	-50
2019-05-28	23	NY.ROSETON.SINK.03	NYSI	-25	-25
2019-05-29	4	MB.WHITESHELL.US.SINK.03	MBSI	-34	-34
2019-05-30	1	MI.LUDINGTON.SINK.02	MISI	-1	-1
2019-05-30	8	MB.WHITESHELL.US.SINK.02	MBSI	-50	-38
2019-06-01	15	NY.ROSETON.SINK.01	NYSI	-100	-100
2019-06-02	11	NY.ROSETON.SINK.05	NYSI	-50	-49
2019-06-02	11	MD.CALVERTCLIFF.SINK.05	NYSI	-25	-25
2019-06-02	12	NY.ROSETON.SINK.25	NYSI	-25	-15
2019-06-02	13	NY.ROSETON.SINK.25	NYSI	-25	-15
2019-06-02	16	NY.ROSETON.SINK.05	NYSI	-50	-50
2019-06-02	17	NY.ROSETON.SINK.05	NYSI	-25	-25
2019-06-03	17	NY.ROSETON.SINK.05	NYSI	-25	-25
2019-06-05	2	NY.ROSETON.SINK.05	NYSI	-10	-10
2019-06-06	21	NY.ROSETON.SINK.05	NYSI	-25	-20
2019-06-06	23	NY.ROSETON.SINK.05	NYSI	-25	-25
2019-06-07	1	NY.ROSETON.SINK.05	NYSI	-50	-50
2019-06-07	2	NY.ROSETON.SINK.05	NYSI	-50	-25
2019-06-07	3	NY.ROSETON.SINK.05	NYSI	-25	-25
2019-06-07	19	NY.ROSETON.SINK.04	NYSI	-30	-30
2019-06-09	14	NY.ROSETON.SINK.25	NYSI	-25	-25
2019-06-09	15	NY.ROSETON.SINK.25	NYSI	-25	-25
2019-06-10	15	NY.ROSETON.SINK.01	NYSI	-50	-50
2019-06-10	17	NY.ROSETON.SINK.01	NYSI	-150	-50
2019-06-10	18	MN.INTFALLS.US.SINK.01	MNSI	-8	-8
2019-06-12	16	NY.ROSETON.SINK.25	NYSI	-50	-25
2019-06-13	1	MB.WHITESHELL.US.SINK.01	MBSI	-34	-34
2019-06-13	6	NY.ROSETON.SINK.01	NYSI	-150	-150
2019-06-13	12	NY.ROSETON.SINK.25	NYSI	-25	-25
2019-06-14	3	MB.WHITESHELL.US.SINK.01	MBSI	-25	-25
2019-06-14	9	NY.ROSETON.SINK.25	NYSI	-50	-20
2019-06-14	10	NY.ROSETON.SINK.25	NYSI	-50	-50
2019-06-14	12	NY.ROSETON.SINK.25	NYSI	-20	-20
2019-06-14	22	NY.ROSETON.SINK.25	NYSI	-25	-25
2019-06-15	14	NY.ROSETON.SINK.03	NYSI	-40	-40
2019-06-15	20	NY.ROSETON.SINK.25	NYSI	-35	-35

2019-06-17	5	NY.ROSETON.SINK.25	NYSI	-50	-50
2019-06-18	13	MB.WHITESHELL.US.SINK.04	MBSI	-34	-1
2019-06-20	17	MD.CALVERTCLIFF.SINK.01	MISI	-50	-50
2019-06-21	7	NY.ROSETON.SINK.04	NYSI	-138	-138
2019-06-21	13	MB.WHITESHELL.US.SINK.01	MBSI	-50	-50
2019-06-22	6	MB.WHITESHELL.US.SINK.04	MBSI	-50	-7
2019-06-23	14	NY.ROSETON.SINK.05	NYSI	-82	-82
2019-06-24	10	NY.ROSETON.SINK.03	NYSI	-32	-32
2019-06-24	10	NY.ROSETON.SINK.25	NYSI	-50	-20
2019-06-25	16	MB.WHITESHELL.US.SINK.03	MBSI	-34	-1
2019-06-25	23	NY.ROSETON.SINK.25	NYSI	-50	-50
2019-06-25	23	NY.ROSETON.SINK.05	NYSI	-70	-70
2019-06-26	3	NY.ROSETON.SINK.25	NYSI	-50	-25
2019-06-26	4	NY.ROSETON.SINK.05	NYSI	-43	-43
2019-06-29	22	MB.WHITESHELL.US.SINK.02	MBSI	-50	-50
2019-07-04	15	MB.WHITESHELL.US.SINK.03	MBSI	-68	-68
2019-07-07	3	NY.ROSETON.SINK.03	NYSI	-35	-35
2019-07-07	4	NY.ROSETON.SINK.25	NYSI	-50	-15
2019-07-07	24	NY.ROSETON.SINK.25	NYSI	-50	-25
2019-07-08	16	MB.WHITESHELL.US.SINK.04	MBSI	-68	-6
2019-07-09	6	MI.LUDINGTON.SINK.02	MISI	-50	-50
2019-07-09	17	NY.ROSETON.SINK.04	NYSI	-126	-11
2019-07-10	20	NY.ROSETON.SINK.05	NYSI	-50	-50
2019-07-10	21	NY.ROSETON.SINK.04	NYSI	-65	-65
2019-07-11	3	NY.ROSETON.SINK.04	NYSI	-138	-11
2019-07-11	3	MI.LUDINGTON.SINK.04	MISI	-54	-1
2019-07-11	13	NY.ROSETON.SINK.25	NYSI	-50	-25
2019-07-11	15	NY.ROSETON.SINK.25	NYSI	-50	-50
2019-07-13	5	MD.CALVERTCLIFF.SINK.25	NYSI	-6	-6
2019-07-15	2	NY.ROSETON.SINK.01	NYSI	-100	-25
2019-07-24	3	NY.ROSETON.SINK.01	NYSI	-50	-50
2019-07-24	5	MB.WHITESHELL.US.SINK.01	MBSI	-33	-33
2019-07-28	4	NY.ROSETON.SINK.25	NYSI	-25	-25
2019-07-28	17	NY.ROSETON.SINK.04	NYSI	-125	-125
2019-08-01	17	NY.ROSETON.SINK.05	NYSI	-56	-56
2019-08-02	13	MB.WHITESHELL.CAN.SOURCE.05	MBSI	25	1
2019-08-02	14	MB.WHITESHELL.CAN.SOURCE.05	MBSI	25	1
2019-08-03	21	NY.ROSETON.SINK.05	NYSI	-50	-50
2019-08-06	3	NY.ROSETON.SINK.03	NYSI	-24	-24
2019-08-07	2	NY.ROSETON.SINK.03	NYSI	-30	-30
2019-08-07	16	MD.CALVERTCLIFF.SINK.04	MISI	-75	-75

2019-08-08	21	MB.WHITESHELL.US.SINK.02	MBSI	-68	-68
2019-08-09	4	NY.ROSETON.SINK.02	NYSI	-26	-26
2019-08-10	21	NY.ROSETON.SINK.01	NYSI	-80	-80
2019-08-12	19	NY.ROSETON.SINK.05	NYSI	-50	-50
2019-08-12	20	MI.LUDINGTON.SINK.05	MISI	-83	-83
2019-08-13	20	NY.ROSETON.SINK.03	NYSI	-25	-25
2019-08-13	21	NY.ROSETON.SINK.05	NYSI	-50	-50
2019-08-13	22	NY.ROSETON.SINK.05	NYSI	-50	-50
2019-08-14	17	NY.ROSETON.SINK.03	NYSI	-25	-25
2019-08-15	22	NY.ROSETON.SINK.03	NYSI	-30	-30
2019-08-16	9	NY.ROSETON.SINK.02	NYSI	-66	-66
2019-08-18	8	NY.ROSETON.SINK.02	NYSI	-28	-28
2019-08-19	1	MB.WHITESHELL.US.SINK.02	MBSI	-66	-6
2019-08-20	1	MN.INTFALLS.US.SINK.04	MNSI	-20	-20
2019-08-22	14	MD.CALVERTCLIFF.SINK.05	MISI	-25	-25
2019-08-23	7	NY.ROSETON.SINK.01	NYSI	-91	-91
2019-08-25	6	MN.INTFALLS.US.SOURCE.05	MNSI	2	2
2019-08-26	2	NY.ROSETON.SINK.03	NYSI	-16	-16
2019-08-26	4	NY.ROSETON.SINK.03	NYSI	-16	-16
2019-08-26	18	NY.ROSETON.SINK.02	NYSI	-55	-55
2019-08-27	21	NY.ROSETON.SINK.02	NYSI	-50	-50
2019-08-28	3	NY.ROSETON.SINK.02	NYSI	-9	-9
2019-08-29	23	MB.WHITESHELL.US.SINK.04	MBSI	-68	-6
2019-08-30	1	NY.ROSETON.SINK.04	NYSI	-146	-81
2019-08-31	7	NY.ROSETON.SINK.04	NYSI	-41	-41
2019-09-01	3	MB.WHITESHELL.US.SINK.01	MBSI	-68	-68
2019-09-01	4	NY.ROSETON.SINK.01	NYSI	-48	-48
2019-09-01	4	MB.WHITESHELL.US.SINK.01	MBSI	-68	-68
2019-09-02	5	MB.WHITESHELL.US.SINK.01	MBSI	-68	-6
2019-09-08	10	MB.WHITESHELL.US.SINK.01	MBSI	-68	-68
2019-09-08	13	NY.ROSETON.SINK.01	NYSI	-35	-35
2019-09-09	24	NY.ROSETON.SINK.23	NYSI	-25	-25
2019-09-09	24	NY.ROSETON.SINK.04	NYSI	-50	-50
2019-09-11	2	NY.ROSETON.SINK.01	NYSI	-100	-1
2019-09-12	24	NY.ROSETON.SINK.05	NYSI	-82	-82
2019-09-13	3	NY.ROSETON.SINK.05	NYSI	-70	-45
2019-09-13	5	NY.ROSETON.SINK.05	NYSI	-70	-40
2019-09-13	23	NY.ROSETON.SINK.05	NYSI	-75	-45
2019-09-14	4	NY.ROSETON.SINK.05	NYSI	-50	-25
2019-09-14	5	NY.ROSETON.SINK.05	NYSI	-50	-25
2019-09-14	6	NY.ROSETON.SINK.05	NYSI	-50	-25

2019-09-14	7	NY.ROSETON.SINK.05	NYSI	-50	-25
2019-09-14	8	NY.ROSETON.SINK.05	NYSI	-50	-25
2019-09-16	23	NY.ROSETON.SINK.25	NYSI	-50	-50
2019-09-19	3	NY.ROSETON.SINK.01	NYSI	-96	-46
2019-09-19	4	MB.WHITESHELL.US.SINK.01	MBSI	-50	-50
2019-09-22	5	MB.WHITESHELL.US.SINK.04	MBSI	-68	-68
2019-09-24	3	NY.ROSETON.SINK.25	NYSI	-17	-17
2019-09-24	3	NY.ROSETON.SINK.05	NYSI	-25	-25
2019-09-26	2	NY.ROSETON.SINK.03	NYSI	-85	-85
2019-09-26	13	NY.ROSETON.SINK.04	NYSI	-25	-25
2019-09-27	4	NY.ROSETON.SINK.02	NYSI	-40	-40
2019-09-27	21	NY.ROSETON.SINK.02	NYSI	-17	-17
2019-09-27	24	NY.ROSETON.SINK.02	NYSI	-37	-37
2019-10-02	15	NY.ROSETON.SINK.02	NYSI	-25	-25
2019-10-03	13	NY.ROSETON.SINK.01	NYSI	-44	-19
2019-10-03	24	NY.ROSETON.SINK.05	NYSI	-50	-50
2019-10-04	10	NY.ROSETON.SINK.25	NYSI	-25	-17
2019-10-05	12	NY.ROSETON.SINK.02	NYSI	-25	-25
2019-10-07	1	NY.ROSETON.SOURCE.02	NYSI	10	10
2019-10-08	11	NY.ROSETON.SINK.25	NYSI	-10	-10
2019-10-08	11	MI.LUDINGTON.SINK.01	MISI	-50	-50
2019-10-09	18	MI.LUDINGTON.SINK.01	MISI	-50	-50
2019-10-12	4	NY.ROSETON.SINK.01	NYSI	-25	-25
2019-10-12	5	NY.ROSETON.SINK.01	NYSI	-8	-8
2019-10-12	6	NY.ROSETON.SINK.01	NYSI	-25	-25
2019-10-12	10	NY.ROSETON.SINK.03	NYSI	-25	-25
2019-10-14	6	MD.CALVERTCLIFF.SINK.05	NYSI	-50	-50
2019-10-14	17	MD.CALVERTCLIFF.SINK.04	NYSI	-50	-50
2019-10-15	3	NY.ROSETON.SINK.25	NYSI	-25	-25
2019-10-15	4	NY.ROSETON.SINK.25	NYSI	-25	-25
2019-10-15	10	NY.ROSETON.SOURCE.04	NYSI	50	21
2019-10-15	11	NY.ROSETON.SOURCE.04	NYSI	5	5
2019-10-15	12	NY.ROSETON.SOURCE.04	NYSI	25	25
2019-10-15	14	NY.ROSETON.SOURCE.04	NYSI	25	25
2019-10-17	1	MN.INTFALLS.US.SINK.04	MNSI	-60	-60
2019-10-17	9	NY.ROSETON.SINK.02	NYSI	-50	-50
2019-10-17	17	MI.LUDINGTON.SINK.06	MISI	-75	-75
2019-10-19	8	NY.ROSETON.SINK.02	NYSI	-100	-75
2019-10-20	8	NY.ROSETON.SINK.02	NYSI	-50	-50
2019-10-21	2	NY.ROSETON.SINK.01	NYSI	-90	-15
2019-10-21	22	MN.INTFALLS.US.SINK.01	MNSI	-25	-25

2019-10-21	22	NY.ROSETON.SINK.01	NYSI	-54	-54
2019-10-21	24	NY.ROSETON.SINK.01	NYSI	-38	-38
2019-10-22	2	NY.ROSETON.SINK.01	NYSI	-15	-15
2019-10-22	11	MD.CALVERTCLIFF.SINK.03	NYSI	-25	-25
2019-10-23	15	NY.ROSETON.SOURCE.03	NYSI	25	25
2019-10-23	16	NY.ROSETON.SOURCE.03	NYSI	25	25
2019-10-24	11	NY.ROSETON.SINK.02	NYSI	-24	-24
2019-10-27	2	NY.ROSETON.SINK.02	NYSI	-50	-50
2019-10-27	8	NY.ROSETON.SINK.02	NYSI	-45	-45
2019-10-27	16	MB.WHITESHELL.US.SINK.04	MBSI	-68	-6
2019-10-27	17	MB.WHITESHELL.US.SINK.04	MBSI	-68	-6
2019-10-28	12	NY.ROSETON.SINK.01	NYSI	-150	-150
2019-10-30	3	MB.WHITESHELL.US.SINK.04	MBSI	-68	-6
2019-11-02	14	NY.ROSETON.SINK.03	NYSI	-21	-21
2019-11-02	24	MB.WHITESHELL.US.SINK.05	MBSI	-68	-68
2019-11-03	9	MD.CALVERTCLIFF.SINK.05	NYSI	-47	-47
2019-11-05	1	NY.ROSETON.SINK.03	NYSI	-50	-50
2019-11-06	23	MB.WHITESHELL.US.SINK.02	MBSI	-75	-10
2019-11-09	6	MD.CALVERTCLIFF.SINK.04	MISI	-132	-132
2019-11-15	12	NY.ROSETON.SINK.04	NYSI	-100	-100
2019-11-21	13	NY.ROSETON.SINK.25	NYSI	-50	-50
2019-11-21	13	NY.ROSETON.SINK.02	NYSI	-25	-25
2019-11-22	8	MD.CALVERTCLIFF.SINK.24	NYSI	-25	-25
2019-11-22	8	NY.ROSETON.SINK.05	NYSI	-50	-43
2019-11-22	9	MD.CALVERTCLIFF.SINK.24	NYSI	-25	-25
2019-11-24	5	NY.ROSETON.SINK.02	NYSI	-134	-59
2019-11-26	3	NY.ROSETON.SINK.03	NYSI	-100	-100
2019-12-08	3	NY.ROSETON.SINK.04	NYSI	-157	-100
2019-12-08	7	NY.ROSETON.SINK.04	NYSI	-50	-50
2019-12-18	18	MD.CALVERTCLIFF.SINK.01	MISI	-50	-50
2019-12-28	14	NY.ROSETON.SINK.01	NYSI	-50	-50
2019-12-31	12	NY.ROSETON.SINK.03	NYSI	-40	-40
2019-12-31	12	MB.WHITESHELL.US.SINK.01	MBSI	-75	-75
2020-01-01	1	NY.ROSETON.SINK.05	NYSI	-27	-27
2020-01-01	12	NY.ROSETON.SINK.03	NYSI	-75	-75
2020-01-01	12	NY.ROSETON.SINK.25	NYSI	-50	-25
2020-01-01	20	NY.ROSETON.SINK.03	NYSI	-50	-50
2020-01-02	10	NY.ROSETON.SINK.02	NYSI	-81	-13
2020-01-02	14	NY.ROSETON.SOURCE.02	NYSI	32	32
2020-01-02	15	NY.ROSETON.SOURCE.02	NYSI	32	32
2020-01-02	19	NY.ROSETON.SOURCE.01	NYSI	25	25

2020-01-02	19	NY.ROSETON.SOURCE.02	NYSI	32	32
2020-01-03	1	NY.ROSETON.SINK.03	NYSI	-49	-49
2020-01-03	1	NY.ROSETON.SINK.25	NYSI	-50	-20
2020-01-07	1	NY.ROSETON.SINK.04	NYSI	-225	-225
2020-01-07	2	NY.ROSETON.SINK.04	NYSI	-200	-5
2020-01-07	23	NY.ROSETON.SINK.04	NYSI	-74	-74
2020-01-07	24	MB.WHITESHELL.US.SINK.04	MBSI	-84	-84
2020-01-08	4	NY.ROSETON.SINK.04	NYSI	-100	-100
2020-01-08	5	MB.WHITESHELL.US.SINK.04	MBSI	-68	-68
2020-01-12	4	MI.LUDINGTON.SINK.05	MISI	-100	-100
2020-01-16	14	MD.CALVERTCLIFF.SINK.01	MISI	-1	-1
2020-01-24	23	MI.LUDINGTON.SINK.02	MISI	-200	-200
2020-01-29	18	MD.CALVERTCLIFF.SINK.05	MISI	-40	-40
2020-02-03	3	NY.ROSETON.SINK.03	NYSI	-125	-125
2020-02-16	11	MB.WHITESHELL.US.SINK.01	MBSI	-80	-80
2020-02-18	23	MN.INTFALLS.US.SINK.01	MNSI	-25	-25
2020-02-22	2	NY.ROSETON.SINK.03	NYSI	-50	-50
2020-02-22	10	MI.LUDINGTON.SINK.01	MISI	-27	-1
2020-02-23	3	NY.ROSETON.SINK.25	NYSI	-25	-25
2020-02-23	3	NY.ROSETON.SINK.03	NYSI	-19	-19
2020-03-02	14	MB.WHITESHELL.US.SINK.02	MBSI	-50	-50
2020-03-04	10	MB.WHITESHELL.US.SINK.04	MBSI	-68	-68
2020-03-09	11	MB.WHITESHELL.US.SINK.05	MBSI	-68	-68
2020-03-19	23	MN.INTFALLS.US.SINK.01	MNSI	-25	-25
2020-03-26	9	NY.ROSETON.SINK.01	NYSI	-50	-50
2020-03-26	10	MN.INTFALLS.US.SINK.01	MNSI	-25	-25
2020-03-27	15	MN.INTFALLS.US.SINK.01	MNSI	-13	-13
2020-03-29	9	NY.ROSETON.SINK.05	NYSI	-163	-163
2020-03-29	21	MB.WHITESHELL.US.SINK.01	MBSI	-50	-50
2020-03-29	21	NY.ROSETON.SINK.01	NYSI	-200	-100
2020-03-29	22	NY.ROSETON.SINK.01	NYSI	-125	-125
2020-04-06	3	NY.ROSETON.SINK.04	NYSI	-100	-100
2020-04-06	9	MI.LUDINGTON.SINK.01	MISI	-29	-1
2020-04-06	24	NY.ROSETON.SINK.04	NYSI	-200	-150
2020-04-08	2	NY.ROSETON.SINK.01	NYSI	-50	-50
2020-04-09	4	NY.ROSETON.SINK.01	NYSI	-150	-100
2020-04-09	23	MI.LUDINGTON.SINK.05	MISI	-100	-100
2020-04-09	23	MI.LUDINGTON.SINK.06	MISI	-25	-25
2020-04-10	1	MI.LUDINGTON.SINK.06	MISI	-15	-15
2020-04-10	1	MI.LUDINGTON.SINK.05	MISI	-100	-100
2020-04-10	9	NY.ROSETON.SINK.25	NYSI	-150	-50

2020-04-10	10	NY.ROSETON.SINK.03	NYSI	-75	-25
2020-04-10	13	MI.LUDINGTON.SINK.01	MISI	-18	-18
2020-04-11	3	NY.ROSETON.SINK.05	NYSI	-50	-25
2020-04-13	1	NY.ROSETON.SINK.03	NYSI	-75	-25
2020-04-14	2	NY.ROSETON.SINK.02	NYSI	-200	-10
2020-04-14	3	NY.ROSETON.SINK.02	NYSI	-200	-10
2020-04-16	3	NY.ROSETON.SINK.04	NYSI	-200	-200
2020-04-17	2	NY.ROSETON.SINK.04	NYSI	-200	-200
2020-04-18	13	NY.ROSETON.SINK.05	NYSI	-100	-50
2020-04-20	21	NY.ROSETON.SINK.05	NYSI	-100	-75
2020-04-20	23	NY.ROSETON.SINK.05	NYSI	-100	-100
2020-04-21	3	NY.ROSETON.SINK.05	NYSI	-100	-50
2020-04-21	9	NY.ROSETON.SINK.02	NYSI	-193	-43
2020-04-21	10	NY.ROSETON.SINK.02	NYSI	-200	-78
2020-04-21	11	MI.LUDINGTON.SINK.02	MISI	-200	-200
2020-04-23	24	NY.ROSETON.SINK.01	NYSI	-100	-100
2020-04-23	24	NY.ROSETON.SINK.02	NYSI	-100	-100
2020-04-24	1	NY.ROSETON.SINK.02	NYSI	-150	-18
2020-04-25	14	MI.LUDINGTON.SINK.01	MISI	-50	-50
2020-04-25	21	NY.ROSETON.SINK.01	NYSI	-200	-200
2020-04-25	23	NY.ROSETON.SINK.01	NYSI	-50	-37
2020-04-26	7	NY.ROSETON.SINK.04	NYSI	-200	-200
2020-04-26	8	NY.ROSETON.SINK.04	NYSI	-200	-121
2020-04-26	14	NY.ROSETON.SINK.01	NYSI	-150	-6
2020-04-27	24	NY.ROSETON.SINK.02	NYSI	-80	-80
2020-04-28	1	NY.ROSETON.SINK.02	NYSI	-129	-129
2020-04-29	8	NY.ROSETON.SINK.25	NYSI	-100	-100
2020-04-29	9	NY.ROSETON.SINK.25	NYSI	-150	-150
2020-04-29	15	NY.ROSETON.SINK.03	NYSI	-25	-25
2020-04-30	2	NY.ROSETON.SINK.05	NYSI	-150	-50
2020-04-30	4	MI.LUDINGTON.SINK.05	MISI	-75	-75
2020-04-30	9	MI.LUDINGTON.SINK.03	MISI	-100	-100
2020-05-01	3	NY.ROSETON.SINK.05	NYSI	-50	-42
2020-05-02	17	MI.LUDINGTON.SINK.02	MISI	-159	-159
2020-05-02	21	MI.LUDINGTON.SINK.03	MISI	-75	-75
2020-05-03	13	NY.ROSETON.SINK.01	NYSI	-100	-96
2020-05-04	1	NY.ROSETON.SINK.02	NYSI	-43	-43
2020-05-09	12	MI.LUDINGTON.SINK.03	MISI	-50	-50
2020-05-09	16	NY.ROSETON.SINK.03	NYSI	-43	-43
2020-05-09	17	NY.ROSETON.SINK.25	NYSI	-100	-25
2020-05-09	18	NY.ROSETON.SINK.25	NYSI	-50	-15

2020-05-14	11	NY.ROSETON.SINK.04	NYSI	-200	-200
2020-05-16	6	NY.ROSETON.SINK.02	NYSI	-200	-25
2020-05-17	8	NY.ROSETON.SINK.04	NYSI	-130	-1
2020-05-18	11	NY.ROSETON.SINK.05	NYSI	-50	-50
2020-05-19	11	NY.ROSETON.SINK.03	NYSI	-50	-50
2020-05-20	8	NY.ROSETON.SINK.05	NYSI	-50	-5
2020-05-21	11	NY.ROSETON.SINK.02	NYSI	-100	-100
2020-05-22	17	MD.CALVERTCLIFF.SOURCE.02	MISI	50	50
2020-05-24	7	NY.ROSETON.SINK.02	NYSI	-100	-25
2020-05-29	4	NY.ROSETON.SINK.05	NYSI	-108	-58
2020-05-29	6	NY.ROSETON.SINK.05	NYSI	-109	-109
2020-05-31	23	NY.ROSETON.SINK.25	NYSI	-25	-25
2020-06-01	2	NY.ROSETON.SINK.03	NYSI	-44	-44
2020-06-01	14	NY.ROSETON.SINK.02	NYSI	-75	-75
2020-06-03	4	MB.WHITESHELL.US.SINK.02	MBSI	-34	-34
2020-06-03	4	NY.ROSETON.SINK.02	NYSI	-100	-20
2020-06-04	3	NY.ROSETON.SINK.02	NYSI	-150	-25
2020-06-07	19	MI.LUDINGTON.SINK.01	MISI	-100	-100
2020-06-09	2	NY.ROSETON.SINK.01	NYSI	-100	-100
2020-06-09	3	MB.WHITESHELL.US.SINK.01	MBSI	-68	-68
2020-06-11	4	MN.INTFALLS.US.SINK.03	MNSI	-9	-9
2020-06-11	4	NY.ROSETON.SINK.25	NYSI	-25	-25
2020-06-11	11	NY.ROSETON.SINK.02	NYSI	-50	-50
2020-06-11	23	NY.ROSETON.SINK.25	NYSI	-25	-25
2020-06-13	2	NY.ROSETON.SINK.02	NYSI	-88	-38
2020-06-13	4	NY.ROSETON.SINK.02	NYSI	-101	-26
2020-06-13	24	NY.ROSETON.SINK.02	NYSI	-100	-25
2020-06-14	1	NY.ROSETON.SINK.02	NYSI	-100	-100
2020-06-15	1	NY.ROSETON.SINK.04	NYSI	-200	-46
2020-06-15	4	NY.ROSETON.SINK.04	NYSI	-153	-153
2020-06-24	1	NY.ROSETON.SINK.25	NYSI	-46	-46
2020-06-24	8	MB.WHITESHELL.US.SINK.02	MBSI	-34	-34
2020-06-25	1	NY.ROSETON.SINK.04	NYSI	-121	-121
2020-06-28	1	MI.LUDINGTON.SINK.01	MISI	-71	-71
2020-07-01	11	MI.LUDINGTON.SINK.02	MISI	-78	-6
2020-07-06	4	NY.ROSETON.SINK.04	NYSI	-75	-75
2020-07-15	24	NY.ROSETON.SINK.04	NYSI	-200	-200
2020-07-17	20	MI.LUDINGTON.SINK.05	MISI	-100	-100
2020-07-20	17	NY.ROSETON.SINK.02	NYSI	-160	-60
2020-07-20	18	NY.ROSETON.SINK.02	NYSI	-70	-15
2020-07-21	12	MI.LUDINGTON.SINK.02	MISI	-100	-100

2020-07-22	3	NY.ROSETON.SINK.03	NYSI	-50	-50
2020-07-22	5	NY.ROSETON.SINK.03	NYSI	-54	-54
2020-07-24	16	MB.WHITESHELL.US.SINK.01	MBSI	-100	-38
2020-07-27	22	MI.LUDINGTON.SINK.01	MISI	-72	-72
2020-07-29	12	MN.INTFALLS.US.SINK.03	MNSI	-8	-8
2020-08-03	15	MD.CALVERTCLIFF.SINK.01	MISI	-50	-50
2020-08-03	15	MI.LUDINGTON.SINK.01	MISI	-6	-6
2020-08-04	2	NY.ROSETON.SINK.04	NYSI	-155	-155
2020-08-10	6	NY.ROSETON.SINK.03	NYSI	-75	-25
2020-08-18	18	MN.INTFALLS.US.SINK.02	MNSI	-7	-7
2020-08-18	22	MI.LUDINGTON.SINK.05	MISI	-46	-46
2020-08-30	2	MI.LUDINGTON.SINK.03	MISI	-50	-50
2020-08-30	4	NY.ROSETON.SINK.03	NYSI	-137	-87
2020-08-30	6	NY.ROSETON.SINK.03	NYSI	-200	-150
2020-08-31	11	MI.LUDINGTON.SINK.01	MISI	-3	-3
2020-09-07	7	MI.LUDINGTON.SINK.05	MISI	-200	-200
2020-09-08	6	MB.WHITESHELL.US.SINK.05	MBSI	-22	-2
2020-09-12	8	MB.WHITESHELL.US.SINK.02	MBSI	-68	-68
2020-09-13	2	MB.WHITESHELL.US.SINK.04	MBSI	-68	-6
2020-09-13	5	NY.ROSETON.SINK.04	NYSI	-90	-33
2020-09-13	5	MB.WHITESHELL.US.SINK.04	MBSI	-68	-6
2020-09-20	5	NY.ROSETON.SINK.25	NYSI	-50	-50
2020-09-20	5	NY.ROSETON.SINK.03	NYSI	-50	-50
2020-09-23	9	MI.LUDINGTON.SINK.01	MISI	-21	-21
2020-09-30	4	NY.ROSETON.SINK.03	NYSI	-100	-100
2020-10-09	23	NY.ROSETON.SINK.03	NYSI	-95	-95
2020-10-09	24	NY.ROSETON.SINK.03	NYSI	-50	-50
2020-10-12	7	NY.ROSETON.SINK.22	NYSI	-25	-25
2020-10-16	3	NY.ROSETON.SINK.01	NYSI	-200	-100
2020-10-17	6	MI.LUDINGTON.SINK.05	MISI	-69	-69
2020-10-18	3	NY.ROSETON.SINK.05	NYSI	-130	-5
2020-10-18	4	NY.ROSETON.SINK.05	NYSI	-178	-178
2020-10-18	10	NY.ROSETON.SINK.02	NYSI	-76	-76
2020-10-18	11	NY.ROSETON.SINK.02	NYSI	-46	-46
2020-10-22	23	NY.ROSETON.SINK.01	NYSI	-200	-136
2020-10-23	3	NY.ROSETON.SINK.04	NYSI	-101	-101
2020-10-23	6	NY.ROSETON.SINK.22	NYSI	-25	-25
2020-10-23	14	NY.ROSETON.SINK.22	NYSI	-25	-25
2020-10-23	14	NY.ROSETON.SINK.05	NYSI	-75	-75
2020-10-23	22	NY.ROSETON.SINK.04	NYSI	-200	-200
2020-10-24	10	MB.WHITESHELL.US.SINK.01	MBSI	-50	-50

2020-10-28	1	NY.ROSETON.SINK.01	NYSI	-84	-3
2020-10-29	1	NY.ROSETON.SINK.03	NYSI	-29	-29
2020-10-30	2	NY.ROSETON.SINK.25	NYSI	-41	-41
2020-10-30	3	NY.ROSETON.SINK.25	NYSI	-50	-50
2020-10-30	4	NY.ROSETON.SINK.25	NYSI	-50	-25
2020-10-31	3	NY.ROSETON.SINK.25	NYSI	-41	-41
2020-10-31	3	NY.ROSETON.SINK.22	NYSI	-20	-20
2020-11-01	18	MI.LUDINGTON.SINK.01	MISI	-100	-100
2020-11-03	1	NY.ROSETON.SINK.04	NYSI	-50	-50
2020-11-03	2	NY.ROSETON.SINK.04	NYSI	-50	-50
2020-11-04	3	MI.LUDINGTON.SINK.01	MISI	-25	-25
2020-11-04	6	NY.ROSETON.SINK.01	NYSI	-50	-50
2020-11-04	23	NY.ROSETON.SINK.22	NYSI	-25	-25
2020-11-04	23	NY.ROSETON.SINK.01	NYSI	-50	-32
2020-11-11	8	MN.INTFALLS.US.SOURCE.02	MNSI	50	50
2020-11-11	12	MB.WHITESHELL.US.SINK.01	MBSI	-68	-68
2020-11-15	20	MB.WHITESHELL.US.SINK.03	MBSI	-68	-68
2020-11-28	4	NY.ROSETON.SINK.03	NYSI	-79	-79
2020-11-28	7	MB.WHITESHELL.US.SINK.03	MBSI	-68	-68
2020-11-29	5	NY.ROSETON.SINK.03	NYSI	-50	-50
2020-11-29	7	NY.ROSETON.SINK.03	NYSI	-28	-28
2020-12-02	24	MN.INTFALLS.US.SOURCE.04	MNSI	50	50
2020-12-03	4	NY.ROSETON.SINK.04	NYSI	-100	-50
2020-12-03	14	MB.WHITESHELL.US.SINK.03	MBSI	-68	-68
2020-12-04	2	MB.WHITESHELL.CAN.SOURCE.01	MBSI	41	2
2020-12-11	19	MN.INTFALLS.US.SINK.01	MNSI	-25	-25
2020-12-12	15	MB.WHITESHELL.US.SINK.01	MBSI	-97	-97
2020-12-17	21	NY.ROSETON.SINK.02	NYSI	-140	-35
2020-12-17	23	NY.ROSETON.SINK.03	NYSI	-100	-100
2020-12-18	6	NY.ROSETON.SINK.03	NYSI	-50	-25
2020-12-19	10	NY.ROSETON.SINK.04	NYSI	-187	-62
2020-12-23	4	NY.ROSETON.SINK.04	NYSI	-200	-200
2020-12-24	5	NY.ROSETON.SINK.01	NYSI	-200	-200
2020-12-24	11	MB.WHITESHELL.US.SINK.05	MBSI	-80	-80
2020-12-25	12	MN.INTFALLS.US.SOURCE.03	MNSI	2	2
2020-12-28	6	NY.ROSETON.SINK.03	NYSI	-50	-50
2020-12-30	19	MD.CALVERTCLIFF.SINK.04	MISI	-49	-49
2021-01-06	17	NY.ROSETON.SINK.02	NYSI	-100	-100
2021-01-07	4	NY.ROSETON.SINK.03	NYSI	-100	-50
2021-01-07	11	NY.ROSETON.SINK.02	NYSI	-168	-38
2021-01-07	13	NY.ROSETON.SINK.02	NYSI	-163	-60

2021-01-08	17	NY.ROSETON.SINK.04	NYSI	-100	-50
2021-01-12	6	MB.WHITESHELL.US.SINK.04	MBSI	-136	-136
2021-01-12	23	NY.ROSETON.SINK.01	NYSI	-140	-90
2021-01-12	24	NY.ROSETON.SINK.01	NYSI	-50	-50
2021-01-13	16	NY.ROSETON.SINK.05	NYSI	-50	-35
2021-01-13	22	MD.CALVERTCLIFF.SINK.01	MISI	-50	-50
2021-01-18	2	NY.ROSETON.SINK.03	NYSI	-50	-50
2021-01-20	23	NY.ROSETON.SINK.04	NYSI	-50	-50
2021-01-21	2	MB.WHITESHELL.US.SINK.04	MBSI	-68	-18
2021-01-21	21	NY.ROSETON.SINK.01	NYSI	-200	-200
2021-01-21	24	MB.WHITESHELL.US.SINK.04	MBSI	-68	-8
2021-01-22	3	MB.WHITESHELL.US.SINK.04	MBSI	-68	-68
2021-01-22	3	MI.LUDINGTON.SINK.04	MISI	-50	-50
2021-01-23	3	NY.ROSETON.SINK.01	NYSI	-200	-100
2021-01-31	13	NY.ROSETON.SINK.01	NYSI	-50	-50
2021-02-01	17	NY.ROSETON.SINK.05	NYSI	-22	-22
2021-02-01	21	NY.ROSETON.SINK.05	NYSI	-49	-49
2021-02-02	2	MB.WHITESHELL.US.SINK.01	MBSI	-100	-16
2021-02-05	5	NY.ROSETON.SINK.05	NYSI	-100	-100
2021-02-11	1	MD.CALVERTCLIFF.SINK.04	MISI	-150	-150
2021-02-18	18	NY.ROSETON.SINK.04	NYSI	-200	-7
2021-03-11	9	MN.INTFALLS.US.SOURCE.02	MNSI	100	100
2021-03-12	7	MN.INTFALLS.US.SOURCE.04	MNSI	55	55
2021-03-25	3	MN.INTFALLS.US.SINK.01	MNSI	-68	-68
2021-03-28	6	MN.INTFALLS.US.SOURCE.03	MNSI	14	14
2021-03-31	6	MN.INTFALLS.US.SOURCE.02	MNSI	100	100
2021-04-06	13	MN.INTFALLS.US.SOURCE.02	MNSI	100	100
2021-04-09	14	MN.INTFALLS.US.SOURCE.04	MNSI	100	100
2021-04-13	21	MB.WHITESHELL.US.SINK.01	MBSI	-84	-16
2021-04-16	17	MB.WHITESHELL.US.SINK.04	MBSI	-68	-68
2021-04-25	18	MB.WHITESHELL.US.SINK.01	MBSI	-68	-1
2021-04-28	4	MB.WHITESHELL.US.SINK.04	MBSI	-68	-19
2021-05-01	24	MB.WHITESHELL.US.SINK.05	MBSI	-50	-2
2021-05-02	10	MN.INTFALLS.US.SOURCE.04	MNSI	21	21
2021-05-03	9	MN.INTFALLS.US.SOURCE.04	MNSI	93	93
2021-05-04	23	MN.INTFALLS.US.SOURCE.04	MNSI	40	40
2021-05-06	13	MB.WHITESHELL.US.SINK.05	MBSI	-50	-50
2021-05-11	9	MN.INTFALLS.US.SOURCE.04	MNSI	25	25
2021-05-11	13	MB.WHITESHELL.US.SINK.04	MBSI	-12	-12
2021-05-13	2	MN.INTFALLS.US.SOURCE.04	MNSI	94	94
2021-05-13	2	MB.WHITESHELL.US.SINK.04	MBSI	-75	-75

2021-05-13	13	MN.INTFALLS.US.SINK.01	MNSI	-25	-25
2021-05-13	13	MB.WHITESHELL.US.SINK.01	MBSI	-50	-22
2021-05-13	14	MN.INTFALLS.US.SINK.01	MNSI	-25	-25
2021-05-13	14	MB.WHITESHELL.US.SINK.01	MBSI	-50	-50
2021-05-13	15	MN.INTFALLS.US.SINK.01	MNSI	-25	-25
2021-05-13	15	MB.WHITESHELL.US.SINK.01	MBSI	-50	-50
2021-05-20	4	MN.INTFALLS.US.SINK.02	MNSI	-20	-20
2021-05-23	21	MB.WHITESHELL.US.SINK.01	MBSI	-50	-50
2021-05-25	2	NY.ROSETON.SINK.05	NYSI	-50	-50
2021-05-25	3	NY.ROSETON.SINK.05	NYSI	-35	-35
2021-05-27	23	NY.ROSETON.SINK.02	NYSI	-100	-100
2021-05-28	13	MB.WHITESHELL.US.SINK.01	MBSI	-33	-33
2021-05-28	14	MB.WHITESHELL.CAN.SOURCE.01	MBSI	5	1
2021-05-29	24	MB.WHITESHELL.US.SINK.04	MBSI	-45	-7
2021-06-06	3	NY.ROSETON.SINK.04	NYSI	-55	-50
2021-06-06	5	NY.ROSETON.SINK.04	NYSI	-50	-50
2021-06-06	6	NY.ROSETON.SINK.04	NYSI	-68	-68
2021-06-13	19	MB.WHITESHELL.US.SINK.01	MBSI	-50	-50
2021-06-13	21	MN.INTFALLS.US.SOURCE.04	MNSI	48	48
2021-06-13	22	MN.INTFALLS.US.SOURCE.03	MNSI	5	5
2021-06-13	22	MN.INTFALLS.US.SOURCE.04	MNSI	50	50
2021-06-14	2	MI.LUDINGTON.SINK.04	MISI	-50	-50
2021-06-16	23	NY.ROSETON.SINK.01	NYSI	-95	-45
2021-06-18	1	NY.ROSETON.SINK.05	NYSI	-50	-50
2021-06-18	17	MN.INTFALLS.US.SOURCE.02	MNSI	60	60
2021-06-24	4	NY.ROSETON.SINK.01	NYSI	-23	-23
2021-06-27	6	MN.INTFALLS.US.SOURCE.05	MNSI	4	4
2021-06-27	13	MI.LUDINGTON.SINK.01	MISI	-18	-18
2021-06-30	1	NY.ROSETON.SINK.04	NYSI	-50	-50
2021-07-01	15	MN.INTFALLS.US.SOURCE.05	MNSI	50	50
2021-07-01	21	NY.ROSETON.SINK.01	NYSI	-103	-103
2021-07-02	22	MN.INTFALLS.US.SOURCE.04	MNSI	12	12
2021-07-02	23	NY.ROSETON.SINK.04	NYSI	-200	-200
2021-07-03	2	MB.WHITESHELL.US.SINK.04	MBSI	-50	-50
2021-07-05	18	MN.INTFALLS.US.SOURCE.02	MNSI	50	50
2021-07-05	22	MN.INTFALLS.US.SOURCE.04	MNSI	100	100
2021-07-11	4	NY.ROSETON.SINK.01	NYSI	-75	-75
2021-07-12	1	NY.ROSETON.SINK.01	NYSI	-100	-100
2021-07-14	18	MN.INTFALLS.US.SOURCE.03	MNSI	50	50
2021-07-16	15	NY.ROSETON.SINK.01	NYSI	-43	-43
2021-07-20	5	MB.WHITESHELL.US.SINK.01	MBSI	-80	-1

2021-07-20	21	MB.WHITESHELL.US.SINK.04	MBSI	-50	-50
2021-07-21	23	MB.WHITESHELL.US.SINK.01	MBSI	-50	-50
2021-07-22	19	MB.WHITESHELL.US.SINK.05	MBSI	-51	-51
2021-07-23	14	MB.WHITESHELL.US.SINK.04	MBSI	-50	-10
2021-07-24	21	MN.INTFALLS.US.SOURCE.05	MNSI	50	50
2021-07-25	5	MB.WHITESHELL.US.SINK.05	MBSI	-34	-34
2021-07-29	11	MB.WHITESHELL.US.SINK.01	MBSI	-50	-50
2021-08-01	19	MN.INTFALLS.US.SOURCE.05	MNSI	6	6
2021-08-02	10	MI.LUDINGTON.SINK.03	MISI	-25	-25
2021-08-02	12	MN.INTFALLS.US.SOURCE.03	MNSI	100	100
2021-08-02	20	MN.INTFALLS.US.SOURCE.03	MNSI	31	1
2021-08-14	16	NY.ROSETON.SINK.01	NYSI	-50	-50
2021-08-14	16	NY.ROSETON.SINK.02	NYSI	-50	-50
2021-09-10	22	MB.WHITESHELL.US.SINK.04	MBSI	-50	-50
2021-09-14	24	NY.ROSETON.SINK.03	NYSI	-15	-15
2021-09-17	3	NY.ROSETON.SINK.02	NYSI	-200	-100
2021-09-23	22	MB.WHITESHELL.US.SINK.03	MBSI	-68	-18
2021-09-23	24	NY.ROSETON.SINK.01	NYSI	-17	-17
2021-09-23	24	NY.ROSETON.SINK.03	NYSI	-17	-17
2021-09-24	4	NY.ROSETON.SINK.03	NYSI	-100	-100
2021-09-24	21	MB.WHITESHELL.CAN.SOURCE.03	MBSI	12	12
2021-09-25	2	NY.ROSETON.SINK.03	NYSI	-25	-25
2021-09-26	4	NY.ROSETON.SINK.02	NYSI	-168	-168
2021-09-26	5	NY.ROSETON.SINK.02	NYSI	-150	-150
2021-09-27	1	NY.ROSETON.SINK.02	NYSI	-194	-76
2021-10-02	1	NY.ROSETON.SINK.05	NYSI	-100	-65
2021-10-03	3	MI.LUDINGTON.SINK.05	MISI	-55	-55
2021-10-06	1	NY.ROSETON.SINK.02	NYSI	-50	-24
2021-10-07	10	MI.LUDINGTON.SINK.01	MISI	-50	-50
2021-10-10	3	NY.ROSETON.SINK.01	NYSI	-75	-25
2021-10-10	4	NY.ROSETON.SINK.01	NYSI	-25	-25
2021-10-11	14	NY.ROSETON.SINK.02	NYSI	-25	-25
2021-10-17	4	NY.ROSETON.SINK.03	NYSI	-22	-22
2021-10-17	17	MI.LUDINGTON.SINK.01	MISI	-50	-50
2021-10-17	24	MI.LUDINGTON.SINK.04	MISI	-50	-50
2021-10-19	24	NY.ROSETON.SINK.01	NYSI	-75	-75
2021-10-20	2	MB.WHITESHELL.US.SINK.01	MBSI	-32	-32
2021-10-20	4	NY.ROSETON.SINK.01	NYSI	-50	-25
2021-10-21	17	NY.ROSETON.SINK.03	NYSI	-75	-75
2021-10-25	4	MN.INTFALLS.US.SINK.03	MNSI	-2	-2
2021-10-25	23	NY.ROSETON.SINK.02	NYSI	-150	-150

2021-10-26	3	NY.ROSETON.SINK.02	NYSI	-50	-50
2021-10-26	4	NY.ROSETON.SINK.02	NYSI	-100	-100
2021-10-29	6	MI.LUDINGTON.SINK.01	MISI	-50	-50
2021-10-29	6	MB.WHITESHELL.US.SINK.01	MBSI	-25	-25
2021-10-29	8	MI.LUDINGTON.SINK.01	MISI	-50	-50
2021-10-30	3	NY.ROSETON.SINK.03	NYSI	-75	-75
2021-10-30	16	NY.ROSETON.SINK.04	NYSI	-50	-50
2021-10-31	22	NY.ROSETON.SINK.03	NYSI	-25	-25
2021-10-31	23	NY.ROSETON.SINK.03	NYSI	-25	-25
2021-10-31	24	NY.ROSETON.SINK.03	NYSI	-25	-25
2021-11-08	13	MI.LUDINGTON.SINK.05	MISI	-100	-100
2021-11-17	12	MN.INTFALLS.US.SINK.01	MNSI	-20	-20
2021-11-19	4	NY.ROSETON.SINK.01	NYSI	-150	-75
2021-11-22	17	MB.WHITESHELL.CAN.SOURCE.02	MBSI	48	48
2021-11-26	20	MD.CALVERTCLIFF.SINK.01	MISI	-39	-39
2021-11-27	1	MN.INTFALLS.US.SINK.04	MNSI	-65	-65
2021-11-29	4	MI.LUDINGTON.SINK.01	MISI	-96	-2
2021-12-01	12	NY.ROSETON.SINK.03	NYSI	-50	-50
2021-12-05	4	NY.ROSETON.SINK.02	NYSI	-200	-200
2021-12-10	18	MN.INTFALLS.US.SINK.03	MNSI	-25	-25
2021-12-11	13	MB.WHITESHELL.US.SINK.03	MBSI	-2	-2
2021-12-16	12	MI.LUDINGTON.SINK.01	MISI	-18	-18
2021-12-18	18	MN.INTFALLS.US.SINK.05	MNSI	-12	-12
2021-12-19	1	MI.LUDINGTON.SINK.01	MISI	-50	-50
2021-12-21	19	MB.WHITESHELL.US.SINK.03	MBSI	-1	-1
2021-12-22	2	NY.ROSETON.SINK.05	NYSI	-91	-91
2021-12-22	3	NY.ROSETON.SINK.05	NYSI	-128	-128
2021-12-25	5	MI.LUDINGTON.SINK.02	MISI	-200	-50
2021-12-26	14	MB.WHITESHELL.US.SINK.01	MBSI	-38	-38
2021-12-28	4	MB.WHITESHELL.US.SINK.04	MBSI	-31	-31
2021-12-28	7	MB.WHITESHELL.US.SINK.04	MBSI	-6	-6
2021-12-28	7	MN.INTFALLS.US.SINK.04	MNSI	-4	-4
2022-01-03	16	MN.INTFALLS.US.SINK.01	MNSI	-4	-4
2022-01-05	3	MD.CALVERTCLIFF.SINK.02	MISI	-199	-199
2022-01-07	22	PQ.OUTAOUAIS.SINK.04	PQAT	-47	-47
2022-01-07	23	PQ.OUTAOUAIS.SINK.04	PQAT	-47	-47
2022-01-08	6	MD.CALVERTCLIFF.SINK.04	MISI	-32	-32
2022-01-08	10	MD.CALVERTCLIFF.SINK.05	MISI	-100	-100
2022-01-10	16	MD.CALVERTCLIFF.SINK.03	MISI	-25	-25
2022-01-15	15	NY.ROSETON.SINK.03	NYSI	-50	-50
2022-01-17	4	NY.ROSETON.SINK.04	NYSI	-200	-200

2022-01-17	10	NY.ROSETON.SINK.01	NYSI	-50	-50
2022-01-17	13	MB.WHITESHELL.US.SINK.01	MBSI	-50	-5
2022-01-19	19	MD.CALVERTCLIFF.SINK.22	MISI	-21	-21
2022-01-19	19	NY.ROSETON.SINK.05	NYSI	-50	-50
2022-01-22	9	NY.ROSETON.SINK.05	NYSI	-100	-100
2022-01-23	6	NY.ROSETON.SINK.05	NYSI	-32	-32
2022-01-23	10	NY.ROSETON.SINK.04	NYSI	-50	-50
2022-01-24	4	PQ.OUTAOUAIS.SINK.02	PQAT	-150	-150
2022-01-24	16	PQ.OUTAOUAIS.SINK.04	PQAT	-59	-59
2022-01-25	7	PQ.OUTAOUAIS.SINK.02	PQAT	-50	-40
2022-01-26	2	PQ.OUTAOUAIS.SINK.04	PQAT	-93	-93
2022-01-26	3	PQ.OUTAOUAIS.SINK.04	PQAT	-99	-99
2022-01-26	21	PQ.OUTAOUAIS.SOURCE.01	PQAT	48	48
2022-01-26	23	PQ.OUTAOUAIS.SINK.04	PQAT	-59	-59
2022-01-28	7	MB.WHITESHELL.US.SINK.01	MBSI	-35	-35
2022-01-28	9	NY.ROSETON.SINK.01	NYSI	-75	-75
2022-01-28	12	NY.ROSETON.SINK.05	NYSI	-50	-50
2022-01-28	23	NY.ROSETON.SINK.01	NYSI	-25	-25
2022-01-28	24	NY.ROSETON.SINK.01	NYSI	-25	-25
2022-01-29	4	PQ.OUTAOUAIS.SINK.01	PQAT	-25	-25
2022-01-30	14	NY.ROSETON.SINK.03	NYSI	-50	-50
2022-01-30	15	NY.ROSETON.SINK.03	NYSI	-50	-50
2022-02-04	4	NY.ROSETON.SINK.02	NYSI	-200	-150
2022-02-04	16	PQ.OUTAOUAIS.SINK.01	PQAT	-100	-100
2022-02-04	22	PQ.OUTAOUAIS.SINK.04	PQAT	-99	-99
2022-02-04	23	PQ.OUTAOUAIS.SINK.04	PQAT	-7	-7
2022-02-05	20	NY.ROSETON.SINK.01	NYSI	-27	-27
2022-02-06	6	NY.ROSETON.SINK.01	NYSI	-50	-50
2022-02-10	24	NY.ROSETON.SINK.03	NYSI	-50	-50
2022-02-11	1	MD.CALVERTCLIFF.SINK.21	NYSI	-5	-5
2022-02-11	2	NY.ROSETON.SINK.03	NYSI	-15	-15
2022-02-11	2	MD.CALVERTCLIFF.SINK.21	NYSI	-5	-5
2022-02-11	3	NY.ROSETON.SINK.03	NYSI	-15	-15
2022-02-13	6	MB.WHITESHELL.US.SINK.02	MBSI	-97	-97
2022-02-14	2	PQ.OUTAOUAIS.SINK.02	PQAT	-180	-180
2022-02-14	12	MB.WHITESHELL.US.SINK.01	MBSI	-17	-17
2022-02-14	14	NY.ROSETON.SINK.01	NYSI	-25	-25
2022-02-14	19	NY.ROSETON.SINK.01	NYSI	-188	-188
2022-02-14	20	PQ.OUTAOUAIS.SOURCE.01	PQAT	55	5
2022-02-23	17	MN.INTFALLS.US.SINK.04	MNSI	-5	-5
2022-02-24	17	NY.ROSETON.SINK.01	NYSI	-100	-25

2022-02-25	22	PQ.OUTAOUAIS.SINK.04	PQAT	-79	-79
2022-02-26	4	PQ.OUTAOUAIS.SINK.04	PQAT	-48	-48
2022-02-28	11	NY.ROSETON.SINK.03	NYSI	-25	-25
2022-02-28	12	NY.ROSETON.SINK.03	NYSI	-20	-20
2022-03-03	13	MB.WHITESHELL.US.SINK.02	MBSI	-13	-13
2022-03-06	16	MB.WHITESHELL.CAN.SOURCE.01	MBSI	14	14
2022-03-08	24	NY.ROSETON.SINK.01	NYSI	-158	-158
2022-03-12	4	MI.LUDINGTON.SINK.05	MISI	-58	-8
2022-03-20	5	NY.ROSETON.SINK.01	NYSI	-10	-10
2022-03-27	1	MB.WHITESHELL.CAN.SOURCE.01	MBSI	16	1
2022-03-27	24	MN.INTFALLS.US.SINK.03	MNSI	-25	-25
2022-03-28	12	NY.ROSETON.SINK.05	NYSI	-9	-9
2022-03-31	17	MN.INTFALLS.US.SINK.03	MNSI	-46	-8
2022-04-01	10	MB.WHITESHELL.US.SINK.04	MBSI	-2	-2
2022-04-01	24	MN.INTFALLS.US.SINK.03	MNSI	-28	-3
2022-04-06	11	NY.ROSETON.SINK.01	NYSI	-33	-33
2022-04-07	7	PQ.OUTAOUAIS.SINK.02	PQAT	-50	-50
2022-04-08	10	NY.ROSETON.SINK.04	NYSI	-100	-100
2022-04-11	9	NY.ROSETON.SINK.02	NYSI	-50	-50
2022-04-11	10	MN.INTFALLS.US.SINK.02	MNSI	-18	-18
2022-04-12	20	MD.CALVERTCLIFF.SINK.02	MISI	-1	-1
2022-04-13	4	PQ.OUTAOUAIS.SINK.04	PQAT	-39	-39
2022-04-14	1	MN.INTFALLS.US.SOURCE.02	MNSI	19	1
2022-04-14	2	PQ.OUTAOUAIS.SINK.02	PQAT	-50	-50
2022-04-14	8	PQ.OUTAOUAIS.SINK.02	PQAT	-59	-59
2022-04-15	9	MN.INTFALLS.US.SOURCE.01	MNSI	50	50
2022-04-16	9	MB.WHITESHELL.CAN.SOURCE.01	MBSI	54	1
2022-04-17	5	MN.INTFALLS.US.SINK.03	MNSI	-25	-25
2022-04-19	22	MB.WHITESHELL.US.SINK.05	MBSI	-51	-27
2022-04-21	5	MN.INTFALLS.US.SOURCE.05	MNSI	20	20
2022-04-21	24	NY.ROSETON.SINK.03	NYSI	-100	-100
2022-04-23	5	NY.ROSETON.SINK.03	NYSI	-50	-25
2022-04-23	7	NY.ROSETON.SINK.03	NYSI	-25	-25
2022-04-24	3	NY.ROSETON.SINK.02	NYSI	-55	-55
2022-04-25	1	NY.ROSETON.SINK.02	NYSI	-100	-100
2022-04-25	3	NY.ROSETON.SINK.02	NYSI	-85	-85
2022-04-25	24	MB.WHITESHELL.US.SINK.04	MBSI	-20	-20
2022-04-27	3	PQ.OUTAOUAIS.SINK.04	PQAT	-99	-99
2022-04-27	4	PQ.OUTAOUAIS.SINK.04	PQAT	-99	-99
2022-04-28	3	MI.LUDINGTON.SINK.01	MISI	-25	-25
2022-04-28	21	PQ.OUTAOUAIS.SOURCE.01	PQAT	24	24

2022-04-30	10	MB.WHITESHELL.US.SINK.03	MBSI	-136	-136
2022-05-01	8	MD.CALVERTCLIFF.SINK.05	MISI	-25	-25
2022-05-01	10	NY.ROSETON.SINK.02	NYSI	-23	-23
2022-05-01	11	NY.ROSETON.SINK.02	NYSI	-39	-39
2022-05-03	3	MI.LUDINGTON.SINK.01	MISI	-50	-50
2022-05-06	2	NY.ROSETON.SINK.04	NYSI	-75	-75
2022-05-06	5	NY.ROSETON.SINK.04	NYSI	-100	-100
2022-05-06	14	MB.WHITESHELL.US.SINK.01	MBSI	-34	-34
2022-05-06	22	NY.ROSETON.SINK.04	NYSI	-77	-64
2022-05-06	24	NY.ROSETON.SINK.04	NYSI	-150	-91
2022-05-07	1	NY.ROSETON.SINK.04	NYSI	-100	-100
2022-05-07	2	NY.ROSETON.SINK.04	NYSI	-150	-41
2022-05-07	4	NY.ROSETON.SINK.04	NYSI	-139	-139
2022-05-07	12	MD.CALVERTCLIFF.SINK.05	MISI	-40	-40
2022-05-07	24	MI.LUDINGTON.SINK.01	MISI	-165	-165
2022-05-08	15	MD.CALVERTCLIFF.SINK.05	MISI	-25	-25
2022-05-12	3	MI.LUDINGTON.SINK.03	MISI	-16	-16
2022-05-13	3	MI.LUDINGTON.SINK.03	MISI	-50	-50
2022-05-13	6	MD.CALVERTCLIFF.SINK.03	MISI	-25	-25
2022-05-19	23	MD.CALVERTCLIFF.SINK.05	MISI	-50	-50
2022-05-22	7	MB.WHITESHELL.US.SINK.03	MBSI	-102	-102
2022-05-25	18	MN.INTFALLS.US.SINK.01	MNSI	-25	-25
2022-05-27	3	MB.WHITESHELL.US.SINK.04	MBSI	-20	-20
2022-05-29	5	NY.ROSETON.SINK.01	NYSI	-60	-60
2022-05-29	24	PQ.OUTAOUAIS.SINK.05	PQAT	-28	-28
2022-05-30	18	PQ.OUTAOUAIS.SINK.03	PQAT	-8	-8
2022-05-30	20	MI.LUDINGTON.SINK.03	MISI	-35	-35
2022-05-31	16	NY.ROSETON.SINK.02	NYSI	-61	-61
2022-06-01	3	MB.WHITESHELL.US.SINK.03	MBSI	-30	-30
2022-06-01	5	MB.WHITESHELL.US.SINK.03	MBSI	-30	-30
2022-06-01	5	MN.INTFALLS.US.SINK.03	MNSI	-1	-1
2022-06-02	5	MB.WHITESHELL.US.SINK.03	MBSI	-50	-50
2022-06-02	5	NY.ROSETON.SINK.03	NYSI	-15	-15
2022-06-02	5	MI.LUDINGTON.SINK.03	MISI	-25	-25
2022-06-02	18	MD.CALVERTCLIFF.SINK.04	MISI	-75	-75
2022-06-04	2	NY.ROSETON.SINK.02	NYSI	-50	-31
2022-06-04	3	PQ.OUTAOUAIS.SINK.02	PQAT	-300	-300
2022-06-04	7	NY.ROSETON.SINK.02	NYSI	-15	-15
2022-06-04	9	NY.ROSETON.SINK.01	NYSI	-48	-48
2022-06-04	9	MN.INTFALLS.US.SINK.01	MNSI	-11	-11
2022-06-05	3	PQ.OUTAOUAIS.SINK.04	PQAT	-99	-99

2022-06-05	4	PQ.OUTAOUAIS.SINK.04	PQAT	-99	-99
2022-06-05	7	PQ.OUTAOUAIS.SINK.04	PQAT	-59	-59
2022-06-06	6	PQ.OUTAOUAIS.SINK.04	PQAT	-57	-57
2022-06-07	1	MB.WHITESHELL.US.SINK.05	MBSI	-59	-59
2022-06-08	10	NY.ROSETON.SINK.03	NYSI	-25	-25
2022-06-09	10	MD.CALVERTCLIFF.SINK.03	NYSI	-10	-10
2022-06-09	23	MB.WHITESHELL.US.SINK.05	MBSI	-13	-13
2022-06-10	7	NY.ROSETON.SINK.05	NYSI	-100	-65
2022-06-11	7	PQ.OUTAOUAIS.SINK.03	PQAT	-47	-47
2022-06-11	16	NY.ROSETON.SINK.04	NYSI	-62	-1
2022-06-11	23	PQ.OUTAOUAIS.SINK.03	PQAT	-103	-59
2022-06-11	24	PQ.OUTAOUAIS.SINK.06	PQAT	-47	-29
2022-06-12	3	MN.INTFALLS.US.SINK.03	MNSI	-5	-5
2022-06-12	7	NY.ROSETON.SINK.03	NYSI	-125	-13
2022-06-12	10	NY.ROSETON.SINK.02	NYSI	-100	-100
2022-06-12	12	MI.LUDINGTON.SINK.02	MISI	-50	-50
2022-06-12	18	PQ.OUTAOUAIS.SINK.02	PQAT	-30	-23
2022-06-12	24	PQ.OUTAOUAIS.SINK.04	PQAT	-59	-52
2022-06-13	3	PQ.OUTAOUAIS.SINK.04	PQAT	-59	-59
2022-06-13	6	PQ.OUTAOUAIS.SINK.04	PQAT	-59	-5
2022-06-14	18	MI.LUDINGTON.SOURCE.05	MISI	20	20
2022-06-15	3	PQ.OUTAOUAIS.SINK.02	PQAT	-200	-9
2022-06-15	4	PQ.OUTAOUAIS.SINK.02	PQAT	-200	-5
2022-06-15	12	MD.CALVERTCLIFF.SINK.05	NYSI	-50	-50
2022-06-16	11	MD.CALVERTCLIFF.SINK.01	NYSI	-18	-18
2022-06-17	12	NY.ROSETON.SINK.01	NYSI	-25	-25
2022-06-17	21	MB.WHITESHELL.US.SINK.05	MBSI	-11	-11
2022-06-18	1	MB.WHITESHELL.US.SINK.05	MBSI	-22	-22
2022-06-18	9	NY.ROSETON.SINK.03	NYSI	-50	-50
2022-06-18	9	PQ.OUTAOUAIS.SINK.03	PQAT	-28	-28
2022-06-18	10	NY.ROSETON.SINK.03	NYSI	-25	-25
2022-06-18	11	NY.ROSETON.SINK.03	NYSI	-50	-50
2022-06-18	13	NY.ROSETON.SINK.03	NYSI	-100	-50
2022-06-18	16	NY.ROSETON.SINK.03	NYSI	-75	-75
2022-06-18	17	NY.ROSETON.SINK.03	NYSI	-75	-75
2022-06-18	19	NY.ROSETON.SINK.03	NYSI	-80	-66
2022-06-19	1	MB.WHITESHELL.US.SINK.01	MBSI	-21	-1
2022-06-26	9	PQ.OUTAOUAIS.SINK.05	PQAT	-28	-28
2022-06-26	13	MI.LUDINGTON.SINK.05	MISI	-85	-42
2022-06-29	17	NY.ROSETON.SINK.06	NYSI	-100	-17
2022-06-29	22	MI.LUDINGTON.SINK.05	MISI	-7	-7

2022-06-30	9	MI.LUDINGTON.SINK.02	MISI	-42	-1
2022-07-01	3	NY.ROSETON.SINK.03	NYSI	-50	-50
2022-07-01	4	NY.ROSETON.SINK.03	NYSI	-50	-50
2022-07-01	5	NY.ROSETON.SINK.03	NYSI	-15	-15
2022-07-02	13	MI.LUDINGTON.SINK.04	MISI	-36	-36
2022-07-02	19	NY.ROSETON.SINK.04	NYSI	-53	-53
2022-07-05	4	PQ.OUTAOUAIS.SINK.04	PQAT	-16	-16
2022-07-05	19	MN.INTFALLS.US.SINK.01	MNSI	-25	-25
2022-07-06	23	MB.WHITESHELL.US.SINK.01	MBSI	-81	-31
2022-07-07	1	MI.LUDINGTON.SINK.01	MISI	-11	-11
2022-07-07	4	NY.ROSETON.SINK.01	NYSI	-15	-15
2022-07-07	7	MI.LUDINGTON.SINK.01	MISI	-50	-50
2022-07-09	15	NY.ROSETON.SINK.06	NYSI	-25	-25
2022-07-09	22	NY.ROSETON.SINK.05	NYSI	-200	-100
2022-07-11	14	NY.ROSETON.SINK.02	NYSI	-50	-50
2022-07-15	11	NY.ROSETON.SINK.01	NYSI	-50	-50
2022-07-16	16	MN.INTFALLS.US.SOURCE.05	MNSI	7	7
2022-07-20	5	NY.ROSETON.SOURCE.05	MISI	30	30
2022-07-21	1	NY.ROSETON.SINK.03	NYSI	-30	-30
2022-07-21	2	MD.CALVERTCLIFF.SINK.03	MISI	-50	-50
2022-07-21	22	NY.ROSETON.SINK.03	NYSI	-25	-25
2022-07-23	11	MD.CALVERTCLIFF.SINK.04	MISI	-50	-50
2022-07-23	16	NY.ROSETON.SINK.04	NYSI	-150	-150
2022-07-23	17	NY.ROSETON.SINK.04	NYSI	-100	-100
2022-07-23	17	MD.CALVERTCLIFF.SINK.04	MISI	-49	-49
2022-07-23	24	MN.INTFALLS.US.SINK.02	MNSI	-99	-99
2022-07-25	13	NY.ROSETON.SINK.01	NYSI	-100	-75
2022-07-27	13	NY.ROSETON.SINK.05	NYSI	-50	-25
2022-07-28	17	NY.ROSETON.SINK.03	NYSI	-50	-50
2022-07-28	22	PQ.OUTAOUAIS.SOURCE.05	PQAT	27	27
2022-07-28	23	NY.ROSETON.SINK.05	NYSI	-15	-15
2022-07-29	14	NY.ROSETON.SINK.03	NYSI	-50	-50
2022-07-30	13	PQ.OUTAOUAIS.SOURCE.02	PQAT	66	4
2022-07-30	18	MD.CALVERTCLIFF.SINK.02	MISI	-150	-2
2022-07-30	23	PQ.OUTAOUAIS.SOURCE.03	PQAT	62	4
2022-08-01	4	PQ.OUTAOUAIS.SINK.03	PQAT	-47	-17
2022-08-01	5	NY.ROSETON.SINK.03	NYSI	-30	-30
2022-08-01	15	MI.LUDINGTON.SINK.05	MISI	-19	-19
2022-08-01	19	PQ.OUTAOUAIS.SOURCE.05	PQAT	98	98
2022-08-01	20	MB.WHITESHELL.CAN.SOURCE.05	MBSI	83	83
2022-08-03	4	NY.ROSETON.SINK.02	NYSI	-150	-65

2022-08-03	20	NY.ROSETON.SINK.01	NYSI	-50	-25
2022-08-05	6	MI.LUDINGTON.SINK.04	MISI	-51	-51
2022-08-06	17	MB.WHITESHELL.CAN.SOURCE.05	MBSI	17	17
2022-08-07	23	NY.ROSETON.SINK.05	NYSI	-100	-75
2022-08-08	20	MD.CALVERTCLIFF.SINK.03	MISI	-15	-15
2022-08-09	3	NY.ROSETON.SINK.05	NYSI	-50	-30
2022-08-09	23	NY.ROSETON.SINK.03	NYSI	-35	-35
2022-08-11	4	MI.LUDINGTON.SINK.03	MISI	-75	-75
2022-08-11	5	MI.LUDINGTON.SINK.03	MISI	-50	-50
2022-08-12	2	PQ.OUTAOUAIS.SINK.02	PQAT	-75	-48
2022-08-12	4	PQ.OUTAOUAIS.SINK.02	PQAT	-75	-58
2022-08-15	14	NY.ROSETON.SINK.05	NYSI	-50	-25
2022-08-20	5	MB.WHITESHELL.CAN.SOURCE.03	MBSI	48	48
2022-08-20	5	MI.LUDINGTON.SINK.03	MISI	-100	-100
2022-08-20	23	NY.ROSETON.SINK.03	NYSI	-50	-50
2022-08-21	4	NY.ROSETON.SINK.03	NYSI	-75	-75
2022-08-27	16	NY.ROSETON.SINK.06	NYSI	-100	-100
2022-08-29	1	NY.ROSETON.SINK.05	NYSI	-100	-75
2022-08-30	14	NY.ROSETON.SINK.04	NYSI	-150	-10
2022-09-02	4	NY.ROSETON.SINK.04	NYSI	-115	-65
2022-09-02	15	MI.LUDINGTON.SINK.01	MISI	-50	-50
2022-09-03	12	PQ.OUTAOUAIS.SINK.01	PQAT	-4	-4
2022-09-04	14	MI.LUDINGTON.SINK.05	MISI	-50	-50
2022-09-05	3	NY.ROSETON.SINK.01	NYSI	-50	-25
2022-09-05	6	NY.ROSETON.SINK.01	NYSI	-200	-150
2022-09-06	14	NY.ROSETON.SINK.06	NYSI	-50	-50
2022-09-14	11	MI.LUDINGTON.SINK.05	MISI	-100	-75
2022-09-15	23	MI.LUDINGTON.SINK.01	MISI	-37	-37
2022-09-18	11	MI.LUDINGTON.SINK.04	MISI	-75	-75
2022-09-18	12	MI.LUDINGTON.SINK.04	MISI	-70	-70
2022-09-19	17	PQ.OUTAOUAIS.SINK.04	PQAT	-44	-7
2022-09-19	18	PQ.OUTAOUAIS.SINK.04	PQAT	-39	-39
2022-09-20	3	NY.ROSETON.SINK.03	NYSI	-50	-50
2022-09-22	2	MN.INTFALLS.US.SINK.04	MNSI	-39	-9
2022-09-22	10	NY.ROSETON.SINK.01	NYSI	-100	-75
2022-09-22	17	MN.INTFALLS.US.SINK.01	MNSI	-25	-25
2022-09-24	4	NY.ROSETON.SINK.02	NYSI	-200	-150
2022-09-24	24	NY.ROSETON.SINK.01	NYSI	-27	-27
2022-09-26	13	NY.ROSETON.SINK.03	NYSI	-75	-75
2022-09-26	22	MN.INTFALLS.US.SINK.05	MNSI	-15	-15
2022-09-26	22	MI.LUDINGTON.SINK.05	MISI	-50	-50

2022-09-26	23	NY.ROSETON.SINK.05	NYSI	-100	-75
2022-09-27	2	MB.WHITESHELL.US.SINK.05	MBSI	-8	-8
2022-09-29	4	MD.CALVERTCLIFF.SOURCE.03	MISI	50	50
2022-09-29	18	PQ.OUTAOUAIS.SINK.02	PQAT	-75	-46
2022-10-02	1	NY.ROSETON.SINK.02	NYSI	-100	-100
2022-10-02	3	NY.ROSETON.SINK.02	NYSI	-99	-99
2022-10-02	7	NY.ROSETON.SINK.02	NYSI	-30	-30
2022-10-02	16	MB.WHITESHELL.US.SINK.01	MBSI	-50	-50
2022-10-02	19	NY.ROSETON.SINK.01	NYSI	-80	-55
2022-10-04	13	MI.LUDINGTON.SINK.05	MISI	-50	-50
2022-10-08	20	MI.LUDINGTON.SINK.02	MISI	-175	-175
2022-10-11	14	MI.LUDINGTON.SINK.04	MISI	-50	-50
2022-10-15	13	MI.LUDINGTON.SINK.05	MISI	-90	-20
2022-10-17	11	PQ.OUTAOUAIS.SINK.03	PQAT	-90	-90
2022-10-17	19	PQ.OUTAOUAIS.SINK.03	PQAT	-33	-33
2022-10-17	21	PQ.OUTAOUAIS.SINK.05	PQAT	-77	-77
2022-10-19	3	MI.LUDINGTON.SINK.03	MISI	-50	-50
2022-10-20	2	NY.ROSETON.SINK.06	NYSI	-115	-115
2022-10-21	22	MI.LUDINGTON.SINK.02	MISI	-54	-54
2022-10-22	14	MN.INTFALLS.US.SINK.01	MNSI	-1	-1
2022-10-23	1	NY.ROSETON.SINK.04	NYSI	-84	-84
2022-10-24	23	NY.ROSETON.SINK.01	NYSI	-74	-39
2022-10-25	2	MD.CALVERTCLIFF.SINK.01	MISI	-50	-50
2022-10-25	15	MD.CALVERTCLIFF.SINK.05	MISI	-50	-50
2022-10-27	6	MD.CALVERTCLIFF.SINK.05	MISI	-50	-50
2022-10-28	11	MI.LUDINGTON.SINK.02	MISI	-100	-100
2022-10-28	19	PQ.OUTAOUAIS.SINK.02	PQAT	-135	-135
2022-10-30	5	MI.LUDINGTON.SINK.03	MISI	-120	-120
2022-11-04	21	MB.WHITESHELL.US.SINK.05	MBSI	-11	-11
2022-11-06	24	MB.WHITESHELL.US.SINK.05	MBSI	-49	-32
2022-11-07	11	MI.LUDINGTON.SINK.02	MISI	-100	-100
2022-11-09	8	MI.LUDINGTON.SINK.05	MISI	-100	-50
2022-11-21	3	PQ.OUTAOUAIS.SOURCE.02	PQAT	284	42
2022-11-21	4	PQ.OUTAOUAIS.SOURCE.02	PQAT	142	142
2022-11-22	20	MI.LUDINGTON.SOURCE.01	MISI	50	50
2022-12-01	9	MI.LUDINGTON.SINK.02	MISI	-5	-5
2022-12-01	19	MI.LUDINGTON.SINK.01	MISI	-50	-50
2022-12-03	15	MN.INTFALLS.US.SINK.05	MNSI	-36	-11
2022-12-06	3	MN.INTFALLS.US.SINK.05	MNSI	-1	-1
2022-12-07	3	MN.INTFALLS.US.SINK.05	MNSI	-75	-75
2022-12-10	9	MB.WHITESHELL.US.SINK.04	MBSI	-2	-2

2022-12-13	2	NY.ROSETON.SINK.01	NYSI	-100	-25
2022-12-14	1	NY.ROSETON.SINK.05	NYSI	-91	-91
2022-12-14	7	MD.CALVERTCLIFF.SINK.05	MISI	-50	-50
2022-12-14	21	MD.CALVERTCLIFF.SINK.02	MISI	-175	-175
2022-12-15	1	NY.ROSETON.SINK.05	NYSI	-67	-67
2022-12-19	2	NY.ROSETON.SINK.02	NYSI	-150	-150
2022-12-19	3	NY.ROSETON.SINK.02	NYSI	-100	-100
2022-12-20	14	NY.ROSETON.SINK.05	NYSI	-100	-100
2022-12-23	13	NY.ROSETON.SINK.04	NYSI	-135	-135
2022-12-24	1	MD.CALVERTCLIFF.SINK.03	MISI	-150	-150
2022-12-24	15	MD.CALVERTCLIFF.SINK.04	MISI	-170	-170
2022-12-24	15	MD.CALVERTCLIFF.SINK.01	MISI	-42	-42
2022-12-24	20	MD.CALVERTCLIFF.SINK.04	MISI	-100	-100
2022-12-25	1	MD.CALVERTCLIFF.SINK.02	MISI	-100	-100
2022-12-25	2	MD.CALVERTCLIFF.SINK.03	MISI	-100	-100
2022-12-25	2	MD.CALVERTCLIFF.SINK.02	MISI	-200	-200
2022-12-26	18	PQ.OUTAOUAIS.SINK.01	PQAT	-96	-1
2022-12-26	21	MD.CALVERTCLIFF.SINK.01	MISI	-100	-100
2022-12-27	1	NY.ROSETON.SINK.04	NYSI	-100	-100
2022-12-27	1	PQ.OUTAOUAIS.SINK.04	PQAT	-59	-59
2022-12-27	3	NY.ROSETON.SINK.04	NYSI	-60	-60
2022-12-28	23	MD.CALVERTCLIFF.SINK.01	MISI	-100	-100
2022-12-29	15	MD.CALVERTCLIFF.SINK.02	MISI	-150	-150
2022-12-30	3	NY.ROSETON.SINK.05	NYSI	-50	-50
2022-12-30	4	NY.ROSETON.SINK.05	NYSI	-200	-200
2022-12-30	5	MB.WHITESHELL.US.SINK.05	MBSI	-52	-52
2022-12-31	17	PQ.OUTAOUAIS.SINK.04	PQAT	-30	-30
2022-12-31	18	PQ.OUTAOUAIS.SINK.04	PQAT	-59	-29
2023-01-09	4	NY.ROSETON.SINK.02	NYSI	-200	-50
2023-01-09	12	MN.INTFALLS.US.SINK.04	MNSI	-34	-34
2023-01-10	15	NY.ROSETON.SINK.01	NYSI	-200	-100
2023-01-16	7	MD.CALVERTCLIFF.SINK.05	MISI	-75	-75
2023-01-17	4	NY.ROSETON.SINK.02	NYSI	-100	-3
2023-01-18	17	PQ.OUTAOUAIS.SINK.01	PQAT	-131	-12
2023-01-20	10	MN.INTFALLS.US.SINK.01	MNSI	-25	-25
2023-01-20	10	MB.WHITESHELL.US.SINK.05	MBSI	-27	-27
2023-01-20	12	MN.INTFALLS.US.SINK.05	MNSI	-25	-25
2023-01-21	16	MI.LUDINGTON.SINK.05	MISI	-117	-1
2023-01-22	8	MI.LUDINGTON.SINK.01	MISI	-42	-2
2023-01-23	9	MN.INTFALLS.US.SINK.05	MNSI	-23	-23
2023-01-24	2	MB.WHITESHELL.US.SINK.05	MBSI	-17	-17

2023-01-24	2	MI.LUDINGTON.SINK.05	MISI	-100	-100
2023-01-24	3	PQ.OUTAOUAIS.SINK.03	PQAT	-5	-5
2023-01-28	1	MI.LUDINGTON.SINK.03	MISI	-5	-5
2023-01-28	4	PQ.OUTAOUAIS.SINK.04	PQAT	-300	-300
2023-01-31	2	MI.LUDINGTON.SINK.03	MISI	-5	-5
2023-02-03	9	MB.WHITESHELL.US.SINK.05	MBSI	-17	-17
2023-02-03	17	PQ.OUTAOUAIS.SOURCE.01	PQAT	73	25
2023-02-03	20	PQ.OUTAOUAIS.SOURCE.03	PQAT	4	4
2023-02-03	23	PQ.OUTAOUAIS.SOURCE.04	PQAT	99	42
2023-02-04	3	PQ.OUTAOUAIS.SOURCE.04	PQAT	99	5
2023-02-04	4	NY.ROSETON.SINK.04	NYSI	-150	-150
2023-02-04	6	PQ.OUTAOUAIS.SOURCE.04	PQAT	94	94
2023-02-04	23	PQ.OUTAOUAIS.SOURCE.04	PQAT	169	169
2023-02-13	14	MI.LUDINGTON.SINK.05	MISI	-160	-160
2023-02-14	22	MN.INTFALLS.US.SINK.01	MNSI	-15	-9
2023-03-04	2	MI.LUDINGTON.SINK.01	MISI	-10	-10
2023-03-08	6	MB.WHITESHELL.US.SINK.02	MBSI	-78	-78
2023-03-09	1	PQ.OUTAOUAIS.SOURCE.02	PQAT	94	21
2023-03-13	21	PQ.OUTAOUAIS.SINK.01	PQAT	-19	-19
2023-03-17	23	MN.INTFALLS.US.SINK.05	MNSI	-25	-25
2023-03-21	10	PQ.OUTAOUAIS.SOURCE.01	PQAT	48	48
2023-04-01	17	MN.INTFALLS.US.SINK.01	MNSI	-6	-6
2023-04-02	12	MI.LUDINGTON.SINK.01	MISI	-127	-127
2023-04-02	20	MD.CALVERTCLIFF.SINK.05	MISI	-100	-100
2023-04-03	17	MB.WHITESHELL.US.SINK.05	MBSI	-41	-41
2023-04-03	17	PQ.OUTAOUAIS.SINK.03	PQAT	-5	-5
2023-04-03	23	MI.LUDINGTON.SINK.03	MISI	-10	-10
2023-04-04	23	MN.INTFALLS.US.SINK.05	MNSI	-8	-1
2023-04-20	14	MI.LUDINGTON.SINK.01	MISI	-3	-3
2023-04-22	1	NY.ROSETON.SINK.04	NYSI	-50	-50
2023-04-22	23	NY.ROSETON.SINK.04	NYSI	-25	-25
2023-04-23	16	MN.INTFALLS.US.SINK.05	MNSI	-6	-6
2023-04-24	3	NY.ROSETON.SINK.04	NYSI	-39	-39
2023-04-28	24	PQ.OUTAOUAIS.SINK.02	PQAT	-100	-100
2023-05-02	4	PQ.OUTAOUAIS.SINK.04	PQAT	-1	-1
2023-05-08	23	MN.INTFALLS.US.SINK.02	MNSI	-3	-3
2023-05-19	12	MB.WHITESHELL.US.SINK.02	MBSI	-14	-14
2023-05-20	9	MB.WHITESHELL.US.SINK.01	MBSI	-14	-14
2023-05-23	1	NY.ROSETON.SINK.01	NYSI	-300	-100
2023-05-30	15	MI.LUDINGTON.SINK.01	MISI	-37	-37
2023-06-04	18	MB.WHITESHELL.CAN.SOURCE.03	MBSI	4	4

2023-06-09	19	MI.LUDINGTON.SINK.01	MISI	-100	-100
2023-06-20	4	NY.ROSETON.SINK.04	NYSI	-138	-138
2023-06-22	23	MN.INTFALLS.US.SINK.01	MNSI	-25	-15
2023-07-08	1	NY.ROSETON.SINK.02	NYSI	-200	-46
2023-07-12	17	MI.LUDINGTON.SINK.05	MISI	-100	-100
2023-07-12	17	MD.CALVERTCLIFF.SINK.05	MISI	-100	-100
2023-07-30	13	MN.INTFALLS.US.SINK.05	MNSI	-25	-25
2023-08-03	21	MN.INTFALLS.US.SINK.01	MNSI	-18	-1
2023-08-03	23	MB.WHITESHELL.US.SINK.01	MBSI	-50	-50
2023-08-04	9	MN.INTFALLS.US.SINK.05	MNSI	-12	-12
2023-08-13	17	MB.WHITESHELL.US.SINK.03	MBSI	-4	-4
2023-08-14	14	MB.WHITESHELL.US.SINK.04	MBSI	-34	-34
2023-08-17	16	MN.INTFALLS.US.SINK.02	MNSI	-15	-15
2023-08-17	20	PQ.OUTAOUAIS.SOURCE.02	PQAT	153	153
2023-08-17	20	PQ.OUTAOUAIS.SOURCE.01	PQAT	131	131
2023-08-20	20	MI.LUDINGTON.SINK.05	MISI	-50	-50
2023-08-21	2	MN.INTFALLS.US.SINK.01	MNSI	-20	-20
2023-08-21	2	MB.WHITESHELL.US.SINK.01	MBSI	-20	-20
2023-08-21	20	MB.WHITESHELL.CAN.SOURCE.05	MBSI	13	1
2023-08-27	12	MB.WHITESHELL.US.SINK.04	MBSI	-15	-15
2023-09-03	16	MB.WHITESHELL.US.SINK.04	MBSI	-34	-34
2023-09-06	3	MB.WHITESHELL.US.SINK.05	MBSI	-41	-41
2023-09-07	2	NY.ROSETON.SINK.05	NYSI	-204	-104
2023-09-10	14	MN.INTFALLS.US.SINK.05	MNSI	-21	-21
2023-09-10	15	MB.WHITESHELL.US.SINK.05	MBSI	-21	-21
2023-09-11	12	MB.WHITESHELL.US.SINK.04	MBSI	-20	-20
2023-09-11	14	MB.WHITESHELL.US.SINK.04	MBSI	-17	-17
2023-09-17	21	MB.WHITESHELL.US.SINK.01	MBSI	-25	-25
2023-09-20	15	MB.WHITESHELL.CAN.SOURCE.04	MBSI	2	2
2023-09-25	15	MN.INTFALLS.US.SOURCE.04	MNSI	75	75
2023-09-26	24	MI.LUDINGTON.SINK.02	MISI	-110	-110
2023-09-27	12	MI.LUDINGTON.SINK.01	MISI	-100	-100
2023-09-28	15	MN.INTFALLS.US.SOURCE.01	MNSI	50	50
2023-10-02	4	MN.INTFALLS.US.SOURCE.05	MNSI	20	20
2023-10-07	1	MN.INTFALLS.US.SINK.02	MNSI	-4	-4
2023-10-07	18	MI.LUDINGTON.SINK.01	MISI	-75	-75
2023-10-08	11	MB.WHITESHELL.CAN.SOURCE.01	MBSI	17	17
2023-10-08	13	MN.INTFALLS.US.SOURCE.01	MNSI	50	50
2023-10-09	15	MN.INTFALLS.US.SINK.05	MNSI	-5	-5
2023-10-10	14	MN.INTFALLS.US.SINK.05	MNSI	-12	-7
2023-10-10	16	MN.INTFALLS.US.SINK.05	MNSI	-25	-25

2023-10-10	23	MB.WHITESHELL.CAN.SOURCE.01	MBSI	24	24
2023-10-11	11	MI.LUDINGTON.SINK.03	MISI	-50	-50
2023-10-13	10	MN.INTFALLS.US.SINK.02	MNSI	-4	-4
2023-10-17	10	MN.INTFALLS.US.SOURCE.01	MNSI	12	12
2023-10-19	21	MB.WHITESHELL.CAN.SOURCE.01	MBSI	17	17
2023-10-20	17	MB.WHITESHELL.CAN.SOURCE.04	MBSI	1	1
2023-10-23	11	MB.WHITESHELL.US.SINK.01	MBSI	-36	-36
2023-10-24	8	MB.WHITESHELL.US.SINK.03	MBSI	-15	-15
2023-10-25	3	NY.ROSETON.SINK.03	NYSI	-100	-50
2023-10-25	5	MB.WHITESHELL.US.SINK.03	MBSI	-20	-20
2023-10-27	3	MN.INTFALLS.US.SOURCE.04	MNSI	3	3
2023-10-30	6	MB.WHITESHELL.CAN.SOURCE.02	MBSI	12	12
2023-10-30	6	MN.INTFALLS.US.SOURCE.02	MNSI	7	7
2023-10-30	14	MN.INTFALLS.US.SOURCE.05	MNSI	25	25
2023-10-30	19	MB.WHITESHELL.CAN.SOURCE.05	MBSI	8	8
2023-11-01	2	MN.INTFALLS.US.SINK.05	MNSI	-26	-11
2023-11-01	7	MN.INTFALLS.US.SINK.06	MNSI	-13	-13
2023-11-10	19	MN.INTFALLS.US.SINK.03	MNSI	-20	-16
2023-11-10	24	MB.WHITESHELL.CAN.SOURCE.02	MBSI	10	10
2023-11-12	10	MN.INTFALLS.US.SINK.05	MNSI	-21	-21
2023-11-13	17	MN.INTFALLS.US.SINK.05	MNSI	-19	-2
2023-11-13	18	MD.CALVERTCLIFF.SINK.05	MISI	-93	-93
2023-11-14	3	NY.ROSETON.SINK.03	NYSI	-75	-25
2023-11-29	3	MB.WHITESHELL.US.SINK.02	MBSI	-6	-6
2023-11-29	13	MI.LUDINGTON.SINK.05	MISI	-200	-100
2023-12-12	2	NY.ROSETON.SINK.05	NYSI	-100	-100

Exhibit “D”

IESO “Sanctions” webpage and IESO “Negotiated Settlements” webpage

Exhibit “D”

to the Affidavit of Robin Doolittle

Sworn before me on October 29, 2025, in accordance with O. Reg. 431/20,
Administering Oath or Declaration Remotely



Commissioner for Taking Affidavits
(or as may be)

October 29, 2025

Keith Edward Hickey, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.

Expires June 24, 2027.

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Compliance Enforcement

MACD enforces compliance through the detection and investigation of potential breaches of the market rules. The Vice President, MACD has the authority to issue non-compliance rulings and impose sanctions, including financial penalties, when the rules have been breached. MACD also administers other rules which may result in repayments to the market.

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Sanctions

Market participants who are found in breach of the market rules or reliability standards may be subject to enforcement sanctions if MACD considers it appropriate. Such possible enforcement sanctions range from non-compliance letters to financial penalties. Persistent breaches may result in de-registration, suspension or termination of the right to participate in the market.

A key goal of enforcement is to encourage compliance which benefits the reliability of the IESO-controlled grid and operations of the IESO-administered markets. In considering the appropriate financial penalty in cases where a penalty is the chosen sanction, Chapter 3, section 6.2.7 of the market rules requires MACD to consider a range of factors such as: actual or potential impacts on the market, other participants and reliability; “the presence and quality” of the market participant’s compliance program; and other factors. Market participants who have developed effective Internal Compliance Programs (ICPs) reduce the likelihood of committing breaches and being subject to enforcement actions.

Below is a list of enforcement sanctions that have been applied by MACD.

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Show 10 entries

Date of Sanction	Market Participant	Description
2020	Citigroup Energy Canada ULC	On December 16, 2020, pursuant to Chapter 3 of the market rules, the IESO issued to CECU a non-compliance letter and ordered the adjustment of settlement amounts to recover from CECU a total of $378,254 for breaches of Chapter 7, section 7.5.8A of the market rules. During the period from January 4, 2012 to January 7, 2018, CECU failed to schedule some promised import and/or export energy at the Michigan-Ontario, Minnesota-Ontario and New York-Ontario borders. When a market participant fails to schedule cross-border energy other than for bona fide and legitimate reasons, they may avoid paying certain settlement amounts and/or may receive unwarranted payments. Failed cross-border trades cause adverse impacts in the IESO-administered markets. For example, avoided payments can result in settlement shortfalls and, in turn, higher costs to consumers. The market rules provide for the adjustment of settlement amounts, including the recovery of avoided settlement amounts and payments received due to cross-border trade failures that are within a market participant's control.

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Compliance Enforcement

MACD enforces compliance through the detection and investigation of potential breaches of the market rules. The Vice President, MACD has the authority to issue non-compliance rulings and impose sanctions, including financial penalties, when the rules have been breached. MACD also administers other rules which may result in repayments to the market.

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Negotiated Settlements

In some circumstances, MACD may enter into a voluntary negotiated settlement with a Market Participant, rather than issuing formal enforcement actions such as the imposition of a financial penalty. MACD's main objective is to secure the best possible outcomes for both reliability and the market, rather than the enforcement of the rules for its own sake. Accordingly, it may consider whether an alternative resolution, which typically includes a range of mitigation and/or remedial features, is preferable.

Below is a list of negotiated settlements agreed upon by MACD.

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Date	Market Participant	Description of Settlement
2021	MAG Energy Solutions Inc.	The IESO has agreed to enter into a settlement with MAG Energy Solutions Inc. (“MAGES”) regarding certain trading activities on the New York-Ontario, Manitoba-Ontario, Michigan-Ontario, Minnesota-Ontario and Quebec-Ontario interties during the period from June 2006 to July 2020. As a result of an investigation, the IESO issued a notice of non-compliance pursuant to Chapter 3 of the Market Rules notifying MAGES that, among other things, the IESO had determined that MAGES failed to schedule certain intertie transactions contrary to Chapter 7, section 7.5.8A of the Market Rules. When a market participant fails to schedule cross-border energy, it may not be charged certain settlement amounts and/or may receive unwarranted payments. The Market Rules provide for the adjustment of settlement amounts, including the recovery of settlement amounts avoided and payments received due to cross-border trade failures that are within a market participant’s control. Without acknowledging or admitting any breach or violation of the Market Rules, MAGES has agreed to voluntarily pay to the IESO the amount of $1.274 million to resolve this matter.

Date	Market Participant	Description of Settlement

Date	Market Participant	Description of Settlement
2021	Rayonier A.M. Canada Enterprises Inc. (formerly Tembec Enterprises Inc) and Rayonier A.M Canada G.P (formerly Tembec General Partnership) (collectively RYAM)	The IESO has entered into a settlement agreement with Rayonier A.M. Canada Enterprises Inc. (formerly Tembec Enterprises Inc.) and Rayonier A.M Canada G.P (formerly Tembec General Partnership), collectively “RYAM”, in relation to matters previously under investigation. Pursuant to Chapter 3, section 6.2.7 of the Market Rules, the IESO has issued a financial penalty and non-compliance letter to RYAM, based upon the breach determinations set out below. While RYAM does not acknowledge or admit to any violation of the Market Rules, for the purposes of the settlement, RYAM does not contest the IESO's determinations of breaches of the following Market Rules: • Chapter 1, section 11.2.1; • Chapter 3, section 6.2.6; • Chapter 5, section 3.5.1.2; • Chapter 7, section 2.1.2.3; • Chapter 7, section 3.3A.11; • Chapter 7, section 3.3.8; • Chapter 7, section 3.5.6.2; • Chapter 7, section 3.5.6.3; • Chapter 7, section 7.4.2; • Chapter 7, section 7.5.1; and

Date	Market Participant	Description of Settlement
		• Chapter 7, section 7.5.2. RYAM has agreed to repay to the IESO the amount of $18,000,000 (Eighteen Million Dollars) in respect of congestion management settlement credit payments received during the period under investigation. RYAM has also agreed to operate the Spruce Falls facility as a non-dispatchable load for the next five years. Based upon the determinations of breach, the IESO has issued a financial penalty and non-compliance letter. The financial penalty requires RYAM to pay $1,000,000 (One Million Dollars) immediately. A remaining part of the penalty, totalling $3,400,000 (Three Million Four Hundred Thousand Dollars) is suspended, but will become payable should RYAM fail to meet its obligations under the settlement agreement. The IESO notes that while under investigation, when notified of certain issues, RYAM took some steps to improve its compliance with the Market Rules. However, the IESO has determined that RYAM breached Chapter 3, section 6.2.6, in relation to a failure to provide a timely and/or comprehensive response to a request for information.

Date	Market Participant	Description of Settlement
2019	Chubu TT Energy Management Inc.	On August 8, 2019, pursuant to Chapter 3, section 6.2.3 of the IESO market rules, the IESO issued a notice (“Notice”) to Chubu TT Energy Management Inc. (“Chubu”) regarding the alleged breach of Chapter 7, section 7.5.8A of the market rules. The Notice related to Chubu’s conduct in certain transactions in the IESO-administered markets between August 25, 2015 and June 16, 2018 over the Michigan-Ontario, Minnesota-Ontario and New York-Ontario interties (the “Subject Transactions”). Specifically, the Notice stated that the IESO is investigating whether Chubu failed to schedule the Subject Transactions other than for bona fide and legitimate reasons, contrary to Chapter 7, section 7.5.8A of the market rules. Without acknowledging or admitting any breach or violation of the market rules, Chubu has agreed to voluntarily pay to the IESO the amount of $650,000, in full and final satisfaction of the allegations in the Notice and the underlying investigation. The IESO has terminated the investigation.

Exhibit "E"

IESO "Issued Compliance and Enforcement Guidance" webpage

Exhibit "E"

to the Affidavit of Robin Doolittle

Sworn before me on October 29, 2025, in accordance with O. Reg. 431/20, Administering Oath or Declaration Remotely



Commissioner for Taking Affidavits
(or as may be)

October 29, 2025

Keith Edward Hickey, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.

Expires June 24, 2027.

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Enabling Compliance

MACD enables compliance by the provision of services that provide information to market participants and the IESO to foster compliance on a forward looking basis. These enabling services include providing, upon request or on its own initiative, compliance and enforcement guidance for specific market rules.

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Issued Compliance and Enforcement Guidance

Compliance and Enforcement Guidance documents provide guidance, on a forward-looking basis, of MACD's view of the meaning of specific market rule provisions and their potential application to compliance and other enforcement determinations. These documents take two forms:

- Statements of Approach – which provide non-binding direction as to MACD's interpretation of the rules and how they may be applied in given circumstances.
- Interpretation Bulletins – these are similar to Statements of Approach in terms of general purpose, but are developed and published by the IESO under the authority of the Market Rules, Chapter 0.1, Section 12. Bulletins are binding on the IESO, subject to the conditions listed in Section 12.1.5 of Chapter 0.1 of the market rules.

Statements of Approach

Statement of Approach	Date Issued
Statement of Approach: Affiliated Entities Participating in the Capacity Auction	October 16, 2025
Statement of Approach: Market Control Entity Disclosure Requirements	April 7, 2025
Statement of Approach: Compliance with Dispatch Instructions within the Compliance Deadband	November 10, 2022
Statement of Approach: Self-Reporting Potential Market Rule Breaches	March 3, 2021
Statement of Approach: Compliance with Requests for Information	December 16, 2020
Statement of Approach: How Internal Compliance Programs are Considered by MACD	December 19, 2013

Interpretation Bulletins

Interpretation Bulletin	Title	Publication Date
IESO_MKRI_0002	Maintaining the Reliability of Supply to Customer Connections	December 9, 2020
IMO_MKRI_0001	Compliance with Dispatch Instructions Issued to Dispatchable Facilities	November 26, 2020
MKRI-1	Costs Reimbursable by the IESO under the Real-Time Generation Cost Guarantee ("RT-GCG") Program Questions and answers related to MKRI-1	August 25, 2014

Documents referenced on this page, but not posted, can be obtained by contacting MACD@ieso.ca with a link to the web page that lists the document and advise whether it needs to be provided in an accessible format. Please allow a minimum of one business day for a response.

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Exhibit “F”

IESO Notice of Non-Compliance dated December 17, 2024

Exhibit “F”

to the Affidavit of Robin Doolittle

Sworn before me on October 29, 2025, in accordance with O. Reg. 431/20, Administering Oath or Declaration Remotely



Commissioner for Taking Affidavits
(or as may be)

October 29, 2025

Keith Edward Hickey, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.

Expires June 24, 2027.

Independent Electricity System Operator
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CONFIDENTIAL

December 17, 2024

Delivered via Workspaces

François Tardif
Director of Risk and Regulatory Affairs
Nexus Energy Inc.
4789 Yonge Street, Suite 916
Ontario, Canada
M2N 0G3

Dear Mr. Tardif,

Re: Market Participant ID Number: 186267
MACD File Reference Number: COM237240
Notice of Non-Compliance and Order

1. As you will be aware, the Independent Electricity System Operator (the "**IESO**"), through its Market Assessment and Compliance Division ("**MACD**"), has been carrying out an investigation (MACD file reference number COM237240) ("**Investigation**") regarding the conduct of NEXUS Energy Inc. ("**NEXUS**") during the period from December 28, 2017, to December 12, 2023.

2. In accordance with the Market Rules for the Ontario Electricity Market ("**Market Rules**"), NEXUS has been provided with details of the Investigation and opportunities to address the matters at issue. The scope of the Investigation is described in the notice pursuant to Chapter 3, section 6.2.3 of the Market Rules issued to NEXUS on April 4, 2024 (the "**Notice**"). Following the Notice, NEXUS requested a meeting with the IESO, which meeting was held through a video conference call on Microsoft Teams ("**Teams**") on April 12, 2024, and NEXUS provided written submissions on July 9, 2024. Following the Notice, NEXUS requested a meeting with the IESO, which meeting was held through a video conference call on Teams on September 4, 2024.

3. Information provided by NEXUS pursuant to the Investigation has been considered by MACD, along with other information considered by MACD to be relevant.

4. The Investigation has been completed. Related determinations on breach and sanction have been made by the IESO, details of which are set out in the Notice of Non-Compliance ("**NNC**") attached hereto as Schedule A. The NNC also sets out the related order ("**Order**") issued by the IESO pursuant to the Market Rules.

5. The IESO has determined that NEXUS breached Chapter 7, section 7.5.8A of the Market Rules in respect of 1,658 intertie transaction failures (being all transaction failures identified in the Notice except for the three transactions on Oct 2, 2018, and January 13, 2023.) These breaches resulted in NEXUS avoiding $2,078,824.92 in congestion rents and receiving $4,931.76 in transmission rights ("**TR**") benefits.

6. Accordingly, in light of these determined breaches, the Order imposes:

   (a) pursuant to Chapter 3, sections 6.6.10A.1 and 6.2.7.4 of the Market Rules, a non-compliance letter for all 1,658 of the breaches, with this letter constituting the non-compliance letter; and

   (b) pursuant to Chapter 3, section 6.6.10A.2 of the Market Rules, adjustment of settlement amounts relating to NEXUS to:

      i. recover $2,078,824.92 in congestion rents avoided by NEXUS due to breaches regarding 1,658 transaction failures identified in the Notice for the period of December 28, 2017, to December 12, 2023 (being all such transaction failures except for the three transactions on Oct 2, 2018, and January 13, 2023); and

      ii. recover $4,931.76 in TR benefits received by NEXUS due to breaches regarding 1,658 transaction failures identified in the Notice for the period of December 28, 2017, to December 12, 2023 (being all such transaction failures except for the three transactions on Oct 2, 2018, and January 13, 2023).

7. The Market Rules set out further opportunities for NEXUS to seek to challenge the breach and sanction determinations, described in part below.

8. NEXUS may challenge part or all of the Order by filing a notice of dispute ("**Notice of Dispute**") pursuant to Chapter 3, section 2 of the Market Rules, as applicable. The Notice of Dispute commences a process by which such dispute ("**Dispute**") may be resolved, including: first, good faith negotiations; secondly, mediation; and ultimately, arbitration. The Market Rules set out applicable timelines in relation to the filing of a Notice of Dispute.

Yours truly,



Glenn McDonald
Vice-President,
Market Assessment and Compliance Division

Attachment: Schedule A - Notice of Non-Compliance/Order

cc: Robert Yeoman/Director - Rule Compliance & Market Surveillance, MACD
Lisa Barnet/Director – Enforcement & Legal, MACD

SCHEDULE A

RE: ALLEGED BREACHES OF MARKET RULES BY

NEXUS ENGERY INC. (COM237240)

NOTICE OF NON-COMPLIANCE

ISSUED BY THE IESO (PURSUANT TO AUTHORITY EXERCISED BY THE

VICE-PRESIDENT OF THE MARKET ASSESSMENT AND COMPLIANCE DIVISION)

December 17, 2024

CONFIDENTIAL

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PART I: OVERVIEW

1. All Chapter and section references in this Notice of Non-Compliance ("**NNC**") relate to the market rules for the Ontario Electricity Market (the "**Market Rules**").

2. The Draft NNC concerns the Market Assessment and Compliance Division's ("**MACD**") investigation COM237240 (the "**Investigation**") into certain failures by NEXUS Energy Inc. ("**NEXUS**") to schedule intertie transactions pursuant to the Market Rules during the period of December 28, 2017 to December 12, 2023 (the "**Relevant Period**").

3. MACD enforces compliance with the Market Rules through the detection and investigation of potential breaches of the Market Rules. The Vice-President of MACD has the authority to independently make determinations as to whether the Market Rules have been breached, and to impose sanctions, including financial penalties, on behalf of the Independent Electricity System Operator ("**IESO**").

4. As discussed in detail below, this NNC concerns 1,658 failed intertie transactions during the Relevant Period. The 1,658 failed transactions are those identified in the Notice (as defined below) and listed in Appendix A thereto (the "**Listed Transactions**"). Each of the Listed Transactions received an "OTH" code by the IESO and each Listed Transaction resulted in NEXUS avoiding paying congestion rents and, in some cases, receiving Transmission Rights ("**TR**") benefits. As a result of the Listed Transactions, NEXUS avoided payment of $**2,078,824.92** in congestion rents and received $**4,931.76** in TR benefits.

PART II: BACKGROUND

A. Parties

i) The Independent Electricity System Operator

5. The IESO is a Crown corporation responsible for directing the operation of Ontario's wholesale electricity market and ensuring the reliability of Ontario's power systems. The IESO's responsibilities include, among other things, the monitoring of, and the issuing of orders, directions or instructions to dispatch generation, dispatchable loads, distribution facilities and transmissions facilities on the IESO-controlled grid. The IESO is also responsible for the administration and supervision of the Market Rules, as well as adherence to North American Reliability Corporation reliability standards and Northeast Power Coordinating Council criteria.

ii) NEXUS Energy Inc.

6. NEXUS is registered as a market participant and trader with the IESO (Market Participant ID Number: 186267). NEXUS has been a registered market participant and trader since in 2017 and has been actively trading in the IESO-administered markets since December 27, 2017.

7. As a registered market participant and trader, NEXUS is required to comply with applicable Market Rules**.**

B. Statutory Framework

i) The Electricity Act, 1998

8. The *Electricity Act, 1998*, S.O. 1998, c. 15, Sched. A (the "***Electricity Act***"), confers upon the IESO broad powers to, among other things, create market rules governing the IESO-controlled grid, establishing and governing markets related to electricity and ancillary services and establishing and enforcing standards and criteria relating to the reliability of electricity service or the IESO-controlled grid.[1]

ii) The Market Rules

9. The Market Rules, pursuant to the *Electricity Act*, seek to establish and govern efficient, competitive and reliable markets for the wholesale sale and purchase of electricity and ancillary services in Ontario.

10. The powers granted to the IESO by the *Electricity Act* and, in turn, the Market Rules, include mechanisms for the monitoring, surveillance and investigation of activities in the IESO-administered markets and the conduct of market participants, among other things, and include such powers and authority as may be necessary or desirable for the purpose of carrying out the IESO's objectives in relation to the IESO-administered markets and the IESO-controlled grid.

11. The rules and standards applicable to the treatment of intertie transactions are set out in the Market Rules and applicable Market Manuals.

12. The rules specific to the Listed Transactions are set out in Chapter 7, sections 7.5.8A and 7.5.8B; Chapter 3, section 6.1.10A and 6.2.7; and in Market Manual, Part 4.3 section 6.6.1 and Part 5.5, sections 1.6.10 and 1.6.10.1.

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[1] *Electricity Act, 1998*, S.O. 1998, c. 15, Sched. A., s. 32.

13. The Chapter 7, sections 7.5.8A and 7.5.8B of the Market Rules read as follows:

> 7.5.8A A registered market participant associated with a registered facility that is a boundary entity shall, other than for the bona fide and legitimate reasons referred to in section 7.5.8B, schedule energy and operating reserve, in accordance with section 6.1.3, with the appropriate scheduling entity, or scheduling entities as the case may be.
>
> 7.5.8B The IESO may take actions pursuant to section 6.6.10A of Chapter 3 and shall assess a real-time import or export failure charge as determined in section 3.8C of Chapter 9 where a registered market participant associated with a registered facility that is a boundary entity fails to schedule energy or operating reserve, in accordance with section 6.1.3 of Chapter 7, with the appropriate scheduling entity, or scheduling entities as the case may be, according to the applicable interchange schedule, other than for bona fide and legitimate reasons as determined by the IESO. Bona fide and legitimate reasons shall include failures caused by actions and circumstances beyond the control of the market participant or due to IESO or external scheduling entity error or action, including those reasons specified in the applicable market manual.

14. Market Manual, Part 4.3 and Part 5.5. set out the IESO's applicable transaction coding principles and interties schedule codes. Market Manual, Part 5.5, section 1.6.10.1 states, "When we manually alter an import or export schedule, we apply one of seven 'reason codes' to apply the appropriate *settlement treatment*" and the reader is expressly referred to "Market Manual 4: Market Operations, Part 4.3: Real-time Scheduling of the Physical Markets" for more information regarding the application of reason codes to import and export schedules.

15. Market Manual, Part 4.3, section 6.6.1 makes clear that transactions that fail and are coded using reason code "OTH" (meaning "OTHER") do not meet the applicable criteria for bona fide and legitimate reasons.

16. As is set out in Market Manual, Part 5.5, section 1.6.10:

> The *market rules* no longer treat *intertie* transaction failures as solely a compliance matter. You will be assessed a *settlement charge* for import and export failures to compensate the market for *intertie* transaction failures that fail for reasons that are within your control, i.e., not "bona fide and legitimate". The *market rules* allow for compliance actions which may include both imposing a financial penalty or recovering any settlement amounts (such as *transmission rights* payments, congestion management *settlement* credits or other *settlement amounts*) that were inappropriately gained or avoided by a market participant.

17. The above provisions applicable to the treatment of intertie transaction failures have remained in effect since June 1, 2006.

18. Also applicable is the Settlement Document "IESO Charge Types and Equations," listing charge types, including charge 103.

19. There are also applicable rules addressing the interpretation and application of the Market Rules, as set out in Chapter 1 of the Market Rules.

C. The Listed Transactions

20. During the Relevant Period, NEXUS completed approximately **40,000** transactions (these transactions were energy imports and exports). During the Relevant Period, NEXUS also failed to schedule 1,658 transactions which the IESO coded as "OTH.

21. Pursuant to the Market Rules and applicable Market Manuals, when there is a failure to schedule an intertie transaction, the IESO will determine the cause of the failure and code the failure as being either for bona fide and legitimate reasons (i.e., reasons that are beyond the market participant's control) or not for bona fide and legitimate reasons (i.e., reasons that are within the market participant's control). Where the IESO codes a failed transaction as "OTH" (meaning ""OTHER"), the IESO has determined the failure is *not* for bona fide and legitimate reasons.

22. Contemporaneous with the IESO's coding determination, the market participant receives a curtailment message notifying the market participant of the reason for the failure and the failure code and, where the failure is coded as "OTH", the market participant is automatically assessed a failure charge, which may or may not be imposed

depending on the Ontario market price, in accordance with the Market Rules. Where a market participant disagrees with the IESO's decision regarding the applicable failure code and/or its assessment of a failure charge, the market participant is afforded the opportunity to dispute the IESO's decision by filing a Notice of Dispute ("**NOD**") with the IESO.

23. In the instance of each of the Listed Transactions, NEXUS was given notice of the failed transactions, that the transactions had been coded by the IESO as "OTH" and, when applicable, that the IESO had imposed a failure charge.

24. As a result of NEXUS's failure to schedule the Listed Transactions, NEXUS avoided paying the applicable intertie congestion price[2] or "**ICP**" (i.e. congestion rents) and, in some cases, also received the benefit of certain TR payments.

25. Below is a breakdown by year of the Listed Transactions, together with the associated congestion rents (ICP) avoided and the TR benefits received by NEXUS:

Year	Avoided Congestion Rent Payments	Accrued Transmission Rights Benefits
2017	$7,759.71	$0
2018	$428,156.13	$0
2019	$180,244.43	$3,182.22
2020	$310,496.28	$1,138.32
2021	$89,837.24	$0
2022	$987,558.03	$7.14
2023	$74,773.10	$604.08
Grand Total	**$2,078,824.92**	**$4,931.76**

[2] There is a uniform market price within Ontario; however, each of the intertie zones may have a different settlement price known as the Intertie Zonal Price (IZP). Intertie transactions are settled at the applicable real-time IZP. The difference between IZP and the Ontario market price is known as the Intertie Congestion Price (ICP). (see Chapter 9, section 3.3).

D. The Investigation

26. On April 4, 2024, the IESO issued a notice pursuant to Chapter 3, section 6.2.3 (the "**Notice**") to NEXUS in respect of 1,661 failed intertie transactions that were coded "OTH" in the period from December 28, 2017 to December 12, 2023. The Notice alleged that NEXUS breached Chapter 7, section 7.5.8A by failing to schedule the intertie transactions other than for bona fide and legitimate reasons.

27. NEXUS was afforded the opportunity to provide written representations and to request a meeting with respect to the breaches alleged in the Notice. NEXUS requested a meeting with the IESO, which meeting was held by way of a Microsoft Teams ("**Teams**") video call on April 12, 2024. NEXUS provided its written representations on July 9, 2024 in response to IESO's Notice ("**Submissions**").

28. NEXUS requested a subsequent meeting with the IESO, which was held by way of Teams again on September 4, 2024.

PART III: SUMMARY OF DETERMINATIONS

i) Determinations of Breach

29. After given due consideration to the Submissions of NEXUS, the IESO has determined there is sufficient evidence to support the determination that NEXUS breached Chapter 7, section 7.5.8A in connection with 1,658 of the 1,661 transactions.

30. As a result of its breaches, the IESO has further determined that NEXUS avoided paying $**2,078,824.92** in congestion rents and received $**4,931.76** in TR benefits.

PART IV: ANALYSIS AND DETERMINATIONS

A. The Alleged Breaches

31. In the Notice, the IESO advised NEXUS that it believed that NEXUS had failed to schedule intertie transactions other than for bona fide and legitimate reasons between December 28, 2017 and December 12, 2023 at the Michigan-Ontario, Minnesota-Ontario, Manitoba-Ontario, Quebec-Ontario and New York-Ontario interties.

32. Chapter 7, section 7.5.8A requires that market participants schedule intertie transactions appropriately. More specifically, if a market participant fails to schedule a transaction in accordance with Chapter 7, section 6.1.3, such a failure to schedule the transaction must be for bona fide and legitimate reasons. Where the failure to schedule

an intertie transaction is not for bona fide and legitimate reasons, such failure constitutes a breach of the Market Rules, specifically, Chapter 7, section 7.5.8A.

33. All of the Listed Transactions were assessed by the IESO as having failed not for bona fide and legitimate reasons and were coded as "OTH".

B. NEXUS Submissions

34. In their Submissions, NEXUS has not disputed any of the transactions in the Listed Transactions. They have neither contested against proper coding of any transaction in the Listed Transactions nor provided any evidence to dispute the charge of the failed transactions being not for bona fide and legitimate reasons.

Summary of Determination of Breaches

35. Based on the record evidence and having given due consideration to NEXUS's Submissions, it is the IESO's determination that the Listed Transactions were properly coded "OTH" and NEXUS's failure to schedule the 1,658 transactions in the Listed Transactions was not for bona fide and legitimate reasons. Accordingly, it is the IESO's determination that in connection with the 1,658 Listed Transactions, NEXUS breached Chapter 7, section 7.5.8A.

C. Consequence of NEXUS's failure to schedule the Listed Transactions

36. When there is export congestion at an intertie between two jurisdictions, exporters pay a higher price than the production cost to supply the export. Similarly, when there is import congestion, Ontario loads pay a higher price to consume the energy than what is paid to importers. The over collection is congestion rent, which is equal to the ICP times the net flow in the export/import direction.

37. However, when congestion exists at an intertie and a market participant fails to schedule its transaction not for bona fide and legitimate reasons, the market participant avoids congestion rents. This results in a congestion rent shortfall which the market (including other market participants and consumers) bears the consequences of.

38. Moreover, if the market participant also holds TRs at the intertie, the market participant may further benefit from the receipt of TR payments. As such, if the market participant holds TRs on the same path as the failed transaction, then the market participant would receive the benefit of the TR payments while having no offsetting congestion rent cost.

i) Determination regarding NEXUS avoidance of Congestion Rents

39. The IESO has reviewed the impact of the Listed Transactions and determined that as a result of NEXUS's breaches, NEXUS avoided paying $**2,078,824.92** in congestion rents.[3]

ii) Determination regarding the NEXUS's receipt of TR payments

40. The IESO has reviewed the impact of the Listed Transactions in connection with the TR payments NEXUS received. The IESO's consideration regarding the TR payments NEXUS received is distinct from simply calculating the total amount of TR payments received. Instead, the IESO has focused its consideration on the amount of TR payments NEXUS received after the offset of any recovered congestion rents ("**TR benefits**").

41. As described above, though the purchase of TRs, market participants are afforded the opportunity to hedge against intertie congestion price risks. Accordingly, where there is a failure to schedule energy, certain of the TR payments will have hedged recovered congestion rents – i.e., where avoided rents have already been recovered which correspond to offsetting TR payments.

42. By way of example: assuming NEXUS held 100 TRs, scheduled 50 MW of energy, failed to schedule 30 MW, and the ICP was $10. NEXUS would have paid $200 in congestion rents (= 20 MW x $10); the IESO would seek payment of another $300 in avoided rents in relation to the failed transaction (= 30 MW x $10); and the total TR payments received by NEXUS would be $1,000 (= 100 TR x $10). The TR benefits NEXUS would have received however are limited to the amounts remaining after the offset of congestion rents. In the within example, the TR benefits NEXUS would have received would be $500 (= $1,000 in TR payments – $200 in avoided rents initially paid – $300 in avoided rents subsequently adjusted).

43. In considering the TR payments received by NEXUS in connection with the Failed Transactions, the IESO has confined its consideration to the TR benefits NEXUS received (i.e. the TR benefits), and not the total TR payments it received.

44. Accordingly, it is the IESO's determination that as a result of NEXUS's breaches, NEXUS received **$4,931.76** in TR benefits in connection with the Listed Transactions.[4]

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[3] See Appendix A.

[4] See Appendix A.

iii) Summary of Determination regarding the consequence of NEXUS's breaches

45. It is the IESO's determination that as a result of the Listed Transactions NEXUS avoided paying $**2,078,824.92**. in congestion rents and received $**4,931.76** in TR benefits to the detriment of the market.

PART V: PRELIMINARY SANCTION ASSESSMENT

A. Sanctions pursuant to the Market Rules

46. Market Rules, Chapter 3, sections 6.6.10A and 6.2.7 set out the available sanctions for a breach of the Market Rules and, in the case of section 6.6.10A, specifically for a breach of Chapter 7, section 7.5.8A.

47. The determination of which sanction(s) to use is at the sole discretion of the IESO.

48. As prescribed by Chapter 3, section 6.6.10A:

> 6.6.10A In respect of a breach of section 7.5.8A of Chapter 7, the *IESO* may:
>
> 6.6.10A.1 issue a letter of non-compliance or impose a financial penalty upon the *market participant* pursuant to sections 6.6.2.3, and 6.6.6; and
>
> 6.6.10A.2 adjust *settlement amounts* paid or payable to a *registered market participant* such as *transmission rights* payments, congestion management *settlement* credits or other *settlement amounts* that the *registered market participant* received or avoided due to an act or omission or a course of conduct of either the *registered market participant* alone or the *registered market participant* by agreement or arrangement with one or more other *market participants* that led to the breach of section 7.5.8A of Chapter 7.

49. As prescribed by Chapter 3, section 6.2.7, where the IESO determines that a market participant has breached the Market Rules the IESO may, pursuant to subsections 6.2.7.4 and 6.2.7.5 (among others), by order do any one or more of the following:

> 6.2.7.4 issue a non-compliance letter in accordance with section 6.6;
>
> 6.2.7.5 impose financial penalties in accordance with section 6.6 indicating the time within which payment of the financial penalty must be made to the *IESO*, provided that no such penalties shall be imposed unless the *IESO* is satisfied that the breach could have been avoided by the exercise of due diligence by the *market participant* or that the *market participant* acted intentionally…

50. The above sanction provisions of the Market Rules have been in effect since June 1, 2006.

B. NEXUS's Submissions regarding Sanctions

51. NEXUS put forward arguments challenging the IESO's right to impose sanctions under Chapter 3, section 6.6.10A of Market Rules on NEXUS in connection with the Listed Transactions. The IESO's consideration and response to NEXUS's arguments are addressed below as follows, (i) congestion rents constitute *settlement amounts* under Chapter 3, section 6.6.10A of the Market Rules; (ii) "egregiousness" is not an element of breach under Chapter 7, section 7.5.8A and not a requirement under Chapter 3, section 6.6.10A; and (iii) NEXUS was/is expected and understood to be aware of the applicable Market Rules at all times, and was apprised of transaction failures as timely as possible.

(i) ***Congestion rents constitute settlement amounts under Chapter 3, section 6.6.10A of the Market Rules***

52. In their Submissions, NEXUS argues that there are no similar provisions in Chapter 9 for the calculation of hourly congestion rent in the way that there are for the hourly settlement amounts for TR and charges, and for congestion management in that Chapter in section 3.6 and 3.5, respectively. In a similar vein, NEXUS claims there is no express reference in Chapter 9 to congestion rents being deemed settlements amounts. As a contrast, NEXUS references the expressly stated real-time import and export failure charges in Chapter 9, section 3.8C.1.

53. NEXUS claims that "Chapter 9 neither identifies ICP as a settlement amount nor describes how ICP will be calculated." Instead, NEXUS states, it is Chapter 7, section

8.1.1A only, in reference to which Chapter 11 defines the ICP.[5] NEXUS submits that congestion rents (or ICP) are not settlement amounts for the purposes of Chapter 3, section 6.6.10A.2 of the Market Rules.

54. The IESO disagrees with NEXUS's position on what constitutes "settlement amount." Chapter 11 defines "settlement amount" to mean "any amount of money to be paid by or to a market participant, determined in accordance with Chapter 9." The IESO understands congestion rent to be an amount of money paid by a market participant to the IESO pursuant to Chapter 9. Specifically, section 3.6.2 sets out the formula for calculating congestion rent, and also states that net congestion rents are collected by the IESO, as contributions to the transmission charge reduction fund ("**TCRF**"). Likewise, the ICP appears as a listed variable under section 3.1.3 of Chapter 9 pursuant to which the ICP is determined in accordance with section 3.1.4A of Chapter 9. Therefore, consistent with the Market Rule definition of "settlement amounts," the ICP is an amount paid by a market participant to the IESO, determined in accordance with Chapter 9.

55. NEXUS states that if congestion rents were "settlement amount" under section 6.6.10A of Chapter 9, a similar provision to section 4.18.1.6 of Chapter 8 that expressly references 6.6.10A would have been made in Chapter 8.[6] This point appears to disregard the lack of need for such a provision in that Chapter given that it already has had such a provision in section 4.18.1.1, addressing the crediting of the Transmission Rights Clearing Account ("**TRCA**") with net congestion rents calculated in accordance with section 3.6.2 of Chapter 9.

56. The collection of congestion rents by the IESO must be understood as a "settlement," defined in Chapter 11 as "the process of transferring payments from those who are required to make payment to those who are required to be paid under the Market Rules." Congestion rents are amounts that intertie traders are required to pay to the IESO in order to settle intertie transactions. In simple terms, congestion rents represent the

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[5] *Intertie congestion price* (ICP) means, in respect of a given dispatch hour, a price equal to the projected market price for energy or operating reserve for a given intertie zone minus the projected uniform market price for energy or operating reserve respectively, in the IESO control area, determined in accordance with section 8.1.1A of Chapter 7

[6] Chapter 8, section 4.18.1 states: The IESO shall establish and maintain a TRCA and shall:

4.18.1.1 credit the TR clearing account, in respect of each settlement hour, the net congestion rents calculated in accordance with section 3.6.2 of Chapter 9; …

4.18.1.6 credit to the TR clearing account any transmission rights settlement credits adjusted under section 6.6.10A.2 of Chapter 3.

difference in money collected from the buyer and paid to the seller. More particularly, it is the difference in price at a particular intertie relative to the uniform Ontario price.[7]

57. Chapter 9 of the Market Rules deals with billings and settlements. While the ICP rent is referenced in Chapter 7 which deals with determining market prices, it is actually settled in accordance with Chapter 9 (as noted earlier). This plainly places the ICP within scope of the definition for "settlement amount", which specifically references Chapter 9 as the Chapter in accordance to which the amount is determined.

58. Contrary to the inference in the NEXUS Submission, the ICP is also referenced in section 3 of Chapter 9, which deals with determination of the hourly settlement amounts. Particularly, sections 3.1.3 and 3.1.4 of Chapter 9 list the ICP as one of the hourly settlement variables and data that must directly be provided to the settlement process by the IESO in order to determine real-time energy prices and quantities, and operating reserve prices and quantities, respectively. "Settlement Process" is defined in the Market Rules as any process administered by the IESO to effect settlement. The ICP must therefore be determined in Chapter 9 as a necessary variable for settlement purposes. It is also referenced in section 3.3.2.1 of Chapter 9 that sets out the formula for determining the hourly settlement amounts in the real-time energy market, and which includes determination of the ICP value within an intertie zone.

59. NEXUS states that Chapter 11 defines ICP only with reference to Chapter 7, section 8.1.1A and not Chapter 9. While the IESO agrees that the ICP definition in Chapter 11 references Chapter 7, section 8.1.1.A, it does not accept that the ICP is settled in Chapter 7. Chapter 7 does not deal with settlements, let alone settlement of the ICP or congestion rent. Rather, as indicated above, Chapter 7 instructs that the ICP associated with each intertie zone must be based on the pre-dispatch schedule. It does not instruct on how it must be settled. Chapter 7 is therefore about scheduling. Chapter 9 is about settlement, including that of the ICP. Settlements of the ICP is not referenced in any other provision of the Market Rules.

60. Additionally, congestion rent is suggested as a settlement amount by way of its designation as a charge type, which is "an identifier designating an item on [a]n … settlement statement." This makes congestion rent an item of settlement and therefore a

[7] When exporting power, exporters pay an amount based on the intertie zonal price (IZP) and the quantity of MWhs exported. Congestion rent is the portion of this amount that exceeds what Ontario consumers would have paid for those MWhs at the Hourly Ontario Energy Price (HOEP). For example, suppose that a MP exports 10 MWhs while the IZP is $50/MWh and the HOEP is $30/MWh. The exporter will pay $500: 10 MWhs multiplied by the IZP of $50/MWh. Of this amount, the congestion rent is $200: 10 MWhs multiplied by the difference between the HOEP ($50/MWh) and the IZP ($30/MWh). Therefore, MPs pay congestion rent.

Chapter 9 subject matter. According to the publicly available "IESO Charge Types and Equations" document, charge type 103 is listed in reference to Chapter 9, section 3.6.2, which characterizes congestion rents as contributions to the TCRF. The TCRF is then factored in as component of the hourly uplift settlement amounts that the IESO shall recover pursuant to Chapter 9, section 3.9.1. All of these are subject matters of settlements, and properly referenced in and determined in accordance with Chapter 9.

61. Finally, the wording "avoided" in section 6.6.10A of Chapter 3 whereby the IESO can "adjust settlement amounts … that registered market participants received or **avoided**…" suggests that "settlement amounts" includes congestion rents. Congestion rents are the only amount(s) that a market participant can avoid that 6.6.10A contemplates. Section 6.6.10A is unlikely to have intended any other charge or amount but congestion rents by that wording.

(ii) ***"Egregiousness" is not an element of breach under Chapter 7 section 7.5.8A and not a requirement under Chapter 3, section 6.6.10A.***

62. In their Submissions, NEXUS argues that its Listed Transactions "do not constitute "egregious behaviour" that Chapter 3, section 6.6.10A of the Market Rules is intended to address." NEXUS relies on a MACD report from 2005 ("**MACD Report**") and Market Rule Amendment Proposal(s) (MR-003080-R00 through MR-00308-R04) from 2006 ("**Amendment Proposal**) to argue that the adjustment of settlement amounts in Chapter 9, section 6.6.10A was intended for transactions failures that amounted to "egregious behaviour," whereby " it is alleged that the market participant unfairly benefited from TR payments, CMSC or other revenues." NEXUS argues that 6.6.10.A is a residual authority to cover those types of circumstances of "egregious behaviour." Rather, NEXUS claims, the import and export failure charges are the intended primary mechanism to address intertie transaction failures. To further support its claim, NEXUS refers to the decision to remove "shall" and replace it with a discretionary "may" in Chapter 7, section 7.5.8B when referring to actions under 6.6.10A. NEXUS disputes that their transactions failures fall into that discretionary category of egregious behaviour.

63. Firstly, the IESO submits that the Amendment Proposal does not displace or otherwise supersede the clear language of the Market Rules. There is nothing in the Chapter 7, section 7.5.8A or sanctions provision in Chapter 3, section 6.6.10A, in terms of a standard of behaviour as precondition for a market participant to meet in order for this provision to apply, including any mental element. The mental state of the market participant is not relevant to, or necessary for the recovery of settlement amounts. There is no foundation for "egregiousness" as an element of breach, in the wording of the provision, or anywhere else in the Market Rules or any Market Manuals. Instead, in

Market Manual 5.5, section 1.6.10 states that the IESO may use its discretion to pursue a compliance investigation:

> The *market rules* no longer treat *intertie* transaction failures as solely a compliance matter. You will be assessed a *settlement* charge for import and export failures to compensate the market for *intertie* transaction failures that fail for reasons within your control, i.e., not "bona fide and legitimate." The *market rules* allow for compliance actions which may include both imposing a financial penalty or recovering any *settlement amounts* (such as *transmission rights* payments, congestion management *settlement* credits or other *settlement amounts*) that were inappropriately gained or avoided by a *market participant*.

64. The IESO submits that the failure charge is strictly concerned with the price impact of a transaction from pre-dispatch to real-time that fails for not bona fide and legitimate reasons. Application of the failure charge is conditional on whether the price moves in the direction that the subject transaction would impact. For example, if the Ontario prices fall after an export transaction fails, it is subject to a failure charge assessment. Section 6.6.10A on the other hand is about settlements of amounts, including congestion rents which funds the TRCA from where the TR payouts are made. Congestion rents therefore address a different issue than the failure charge.

65. The strict basis for adjusting settlement amounts under 6.6.10A is the same for the failure charges; that is, the transaction failures were attributable to the market participant. If there is any test in that provision in respect of avoided settlement amounts, it is: but for the transaction failure, would the market participant have avoided the payments? If the answer is no, then the IESO is in position to recover those avoided payments.

66. Secondly, at the time of the Amendment Proposal, the IESO had identified that the operating regime to deal with intertie transaction failures within the control of market participants had "not been effective". Accordingly, the IESO introduced an automatic failure charge system with the expectation that market participants would be incentivized "to ensure that they navigate the neighbouring markets successfully". However, in drafting and enacting the new Market Rules, the IESO maintained its discretion to impose sanctions for a breach of the market rules without any precondition that a market participant must first have engaged in egregious behaviour.

67. The premise Amendment Proposal and the MACD Report was that the failure charges would curb transaction failures. However, they had limited impact because it has become clear that the problem of intertie transaction failures within the control of market

participants has persisted and has resulted in significant costs imposed upon consumers. Notably, as the Market Surveillance Panel (MSP) has observed:

> From January 2010 to April 2016, Ontario consumers have paid for approximately $11 million in congestion rent shortfall induced by intertie failures within the participant's control. This outcome is clearly inappropriate.[8]

68. The MSP has confirmed that since the failure charge fails to account for the congestion rent shortfall created by transaction failure, there is no compelling reason not to recover congestion rents avoided. It is unreasonable that conduct must be seen as egregious to address avoidance of monies that create shortfall that others (other market participants and consumers) who are not at fault pay, for the failures brought about by NEXUS. This is unjust and this is why MSP recommended that IESO include congestion rents in its methodology used to set the intertie failure charge.

69. Between 2017 and 2023 NEXUS has avoided paying approximately $2 million dollars in obligatory congestion rents, which is now picked by the TRCA and the Ontario rate payers.

70. When a market participant fails a transaction, it is their fault, and when they receive financial benefits as a result, at the expense of others in the market, it's important that the participant should be responsible for that. It is not a question of egregiousness or moral culpability. It is that the financial gain does not rightfully belong to them, and it would be fair to appropriate it to the rightful place.

71. The notion of egregiousness as a standard of conduct would be more appropriate under sanctions' consideration, in the likeness of a penalty that may factor in intentionality. Recovery of monies that were never properly NEXUS's is a matter of settlement not "sanction" in the sense of a penalty.

(iii) ***NEXUS expected and understood to be cognizant of the applicable Market Rules, and apprised of the failed transactions as timely as possible***

72. NEXUS alleges that had the IESO made NEXUS aware of the matter "at any time during the last 6+ years, it would have immediately modified its trading behaviour or sought further clarifications from MACD consistent with its commitment to compliance

[8] MSP Report, November 2015 – April 2016, page 81; available at: https://www.oeb.ca/sites/default/files/msp-report-nov2015-apr2016_20170508.pdf.

with applicable market rules." NEXUS claims that the IESO's delay in alerting NEXUS of this matter has therefore caused NEXUS significant prejudice.

73. Firstly, the IESO submits that there is no prescribed limitation period applicable either to the assessment of any breach under Chapter 7, section 7.5.8A or to the assessment of sanctions under Chapter 3, sections 6.6.10A or 6.2.7. The IESO is wholly within its authority to review and assess sanctions pursuant thereto in connection with the Listed Transactions

74. Secondly, the IESO does not accept that there has been any inordinate or undue delay. The IESO disagrees that NEXUS was not made aware of the matter in the last 6+ years. In fact, in each instance of the failed transactions, NEXUS was notified with the delivery of the failure code "OTH," and where applicable, through the failure charges imposed on the transactions. In each instance, not only was NEXUS notified but also afforded the right to challenge the subject transaction through the NOD process.

75. Additionally, delay alone does not amount to prejudice. It must be unreasonable or inordinate within the context. As the court makes clear in *Blencoe* "[s]taying proceedings for the mere passage of time would be tantamount to imposing a judicially created limitation period."[9] NEXUS has failed to adduce any evidence of significant prejudice resulting from the delay.

76. Further, as a market participant, NEXUS is expected and understood to be cognizant of the applicable Market Rules as they are bound by them. The language of the Market Rules is clear, and NEXUS is required to govern its conduct in accordance therewith. In addition to NEXUS having the opportunity to seek clarification on a given Market Rule, NEXUS also had the opportunity to avail itself to IESO's Sanction and Negotiated Settlements Webpage to learn how similar breaches are sanctioned beyond the import/export failure charges. Indeed, NEXUS also had the benefit of the MSP report (referenced above) since May 2017, to alert them to this possible outcome.

77. The Market Rules make clear that where a market participant fails to schedule energy other than for bona fide and legitimate reasons, "the IESO may take actions pursuant to section 6.6.10A of Chapter 3 and shall assess a real-time import or export failure charge as determined in section 3.8C of Chapter 9…".[10]

As acknowledged by NEXUS, and as already stated, the applicable Market Rules – including, specifically, Chapter 7, section 7.5.8A and Chapter 3, Section 6.6.10 – came into

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[9] *Blencoe v. British Columbia (Human Rights Commission)*, [2002] 2 S.C.R. 307 ["***Blencoe***"] at para 101.

[10] Market Rule, Chapter 7, section 7.5.8B

effect on June 1, 2006 and have remained in effect throughout the Relevant Period. As a market participant, NEXUS is subject to the Market Rules and required to comply with applicable Market Rules.

78. The IESO is of the view that the above is dispositive of the issue.

C. Summary of Sanction Determination

79. Having regard to the facts and circumstances concerning the 1,658 breaches of Chapter 7, section 7.5.8A, as determined by the IESO, it is the IESO's preliminary assessment that:

(i) a non-compliance letter be issued to NEXUS pursuant to Chapter 3, sections 6.6.10A.1 and 6.2.7.4 regarding its 1,658 breaches of the Market Rules; and

(ii) there be an adjustment of settlement amounts pursuant to Chapter 3, section 6.6.10A.2 to:

i. recover $**2,078,824.92** of the congestion rents (ICPs) avoided by NEXUS in connection with the Listed Transactions for the period of December 28, 2017, to December 12, 2023; and

ii. recover **$4,931.76** in TR benefits received by NEXUS in connection with 1,658 of the Listed Transactions for the period of December 28, 2017, to December 12, 2023.

80. Considering the IESO's determination to adjust settlement amounts, the IESO has determined that it would not be appropriate to issues a financial penalty pursuant to Chapter 3, section 6.6.10A.1 or section 6.2.7.5.

D. Preliminary Sanction Assessment Analysis

i) Sanction Assessment pursuant to sections 6.6.10A.1 and 6.2.7.4

81. Where it has been determined that a market participant has breached Chapter 7, section 7.5.8A, both section 6.6.10A and section 6.2.7 of Chapter 3 afford the IESO the authority to exercise its discretion and issue a non-compliance letter or a financial penalty.

82. Having regard to the above determinations, the IESO has determined it is appropriate to issue a non-compliance letter to NEXUS pursuant to Chapter 3, section 6.6.10A and 6.2.7 in connection with its 1,658 breaches of Chapter 7, section 7.5.8A.

83. Additionally, and having regard to the IESO's determination to adjust settlement amounts pursuant to Chapter 3, section 6.6.10A.2– as set out in section (ii) below – the IESO has determined that it is not necessary to impose a financial penalty on NEXUS pursuant to Chapter 3, section 6.6.10A.1 and/or section 6.2.7.5.

84. However, to the extent necessary, the IESO reserves its rights to review and assess the relevant factors pursuant to Chapter 3, sections 6.6.10A.1 and 6.2.7.5 and to impose a financial penalty, should the IESO fail to recover the settlement amounts, as determined.

ii) Adjustment of Settlement Amounts pursuant to section 6.6.10A.2

85. Where it has been determined a market participant has breached Chapter 7, section 7.5.8A, pursuant to Chapter 3, section 6.6.10A.2 the IESO may adjust settlement amounts that were paid or payable to the market participant, and which include TR payments and other settlement amounts that a market participant received or avoided as a result of the breach(es).

86. The term "settlement amount" is defined in Chapter 11 to mean "any amount of money to be paid by or to a market participant, determined in accordance with Chapter 9". Both congestion rents and TR payments are amounts of money to be paid by or to a market participant in accordance with Chapter 9 (see sections 3.3 and 3.6.2).

87. Accordingly, to the extent the IESO has determined that such amounts have been paid to, received or avoided by a market participant as a result of conduct which the IESO has determined to be in breach of Chapter 7, section 7.5.8A, it is within the IESO's discretion to recover those amounts pursuant to Chapter 3, section 6.6.10A.2.

(a) Recovery of Avoided Congestion Rents

88. As detailed above, the IESO has determined that as a result of NEXUS's 1,658 breaches NEXUS avoided $**2,078,824.92** in congestion rents to the detriment of the market.

(b) Recovery of TR Payments

89. As detailed above, the IESO has determined that as result of NEXUS's 1,658 breaches NEXUS received **$4,931.76** in TR benefits.

90. As also detailed above, while section 6.6.10A.2 expressly contemplates settlement adjustments encompassing all of the TR payments NEXUS received, it is the IESO's determination that the focus of the settlement adjustment should be limited to the TR benefits received by NEXUS.

91. Accordingly, and for all of the above reasons, it is the IESO's determination that, pursuant to section 6.6.10A.2, it is appropriate to seek recovery of the TR benefits NEXUS received as a result of its breaches.

PART VI: ORDER

92. For the reasons set out above, the IESO orders:

(i) Pursuant to Chapter 3, sections 6.6.10A.1 and 6.2.7.4 of the Market Rules, NEXUS shall receive a non-compliance letter indicating that NEXUS breached Chapter 7, section 7.5.8A of the Market Rules in respect of 1,658 intertie transaction failures identified in the Notice (being all such transactions except 3 transactions that were adjusted via the NOD process).

(ii) Pursuant to Chapter 3, section 6.6.10A.2 of the Market Rules, the IESO shall adjust settlement amounts relating to NEXUS to:

i. recover $**2,078,824.92** in congestion rents (ICPs) avoided by NEXUS due to the breaches of Chapter 7, section 7.5.8A of the Market Rules regarding 1,658 Listed Transactions identified in the Notice for the period of December 28, 2017, to December 12, 2023 (being all such transactions except for the 3 Transactions); and

ii. recover **$4,931.76** in TR benefits received by NEXUS due to the breaches of Chapter 7, section 7.5.8A of the Market Rules regarding 1,658 Listed Transactions identified in the Notice for the period of December 28, 2017, to December 15, 2023 (being all such transactions except for the 3 Transactions).

Exhibit “G”

IESO invoice dated February 14, 2025

Exhibit “G”

to the Affidavit of Robin Doolittle

Sworn before me on October 29, 2025, in accordance with O. Reg. 431/20, Administering Oath or Declaration Remotely



Commissioner for Taking Affidavits
(or as may be)

October 29, 2025

Keith Edward Hickey, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.

Expires June 24, 2027.

Independent Electricity System Operator
PHYSICAL INVOICE

Independent Electricity System Operator
Station A, Box 4474
Toronto, ON
M5W 4E5

HST: 870513959RT0002
Issue / Re-Issue Date: 14-FEB-2025

NEXUS ENERGY INC.
4789 Yonge St, Suite 916
Toronto, ON M2N 0G3
Canada

Invoice: PI00051674
Invoice Date: 14-FEB-2025
MP ID: 186267
MP GST/HST: 703051094 RT0001

Please send payment by WIRE or EFT to:

Bank Name: **TD Bank**
Bank ID Number: **0004**
Bank Account Number: **0690-0458762**

Bank Acc Type: **Settlement Clearing**
Bank Transit Number: **10202**

For all inquiries contact:
IESO Account Representative
Tel: 905-403-6900
Toll Free: 1-888-448-7777

Comments:

Charges for settlement statements issued: From 01-JAN-2025 To 31-JAN-2025

Charge Type	Description	Amount
104	TRANSMISSION RIGHTS SETTLEMENT CREDIT	($1,618,912.68)
105	CONGESTION MANAGEMENT SETTLEMENT CREDIT FOR ENERGY	($334,070.43)
135	REAL-TIME IMPORT FAILURE CHARGE	$856.37
136	REAL-TIME EXPORT FAILURE CHARGE	$116,161.68
150	NET ENERGY MARKET SETTLEMENT UPLIFT	$94,101.98
155	CONGESTION MANAGEMENT SETTLEMENT UPLIFT	$45,858.32
169	STATION SERVICE REIMBURSEMENT DEBIT	$1,762.74
170	LOCAL MARKET POWER REBATE	($25,858.97)
183	GENERATION COST GUARANTEE RECOVERY DEBIT	$16,012.52
186	INTERTIE FAILURE CHARGE REBATE	($4,668.85)
250	10-MINUTE SPINNING MARKET RESERVE HOURLY UPLIFT	$10,410.65
252	10-MINUTE NON-SPINNING MARKET RESERVE HOURLY UPLIFT	$7,458.82
254	30-MINUTE OPERATING RESERVE MARKET HOURLY UPLIFT	$3,559.71
450	BLACK START CAPABILITY SETTLEMENT DEBIT	$626.28
451	HOURLY REACTIVE SUPPORT AND VOLTAGE CONTROL SETTLEMENT DEBIT	$7,304.34
452	MONTHLY REACTIVE SUPPORT AND VOLTAGE CONTROL SETTLEMENT DEBIT	$386.68
454	REGULATION SERVICE SETTLEMENT DEBIT	$20,709.14
653	EXPORT TRANSMISSION SERVICE CHARGE	$134,631.33
900	GST/HST CREDIT	($1,186,937.73)

950	GST/HST DEBIT		$410,550.62
1111	REAL-TIME ENERGY SETTLEMENT AMOUNT FOR IMPORTS		($4,598,566.26)
1113	REAL-TIME ENERGY SETTLEMENT AMOUNT FOR EXPORTS		$7,646,692.92
1131	INTERTIE OFFER GUARANTEE SETTLEMENT CREDIT		($3,635,790.85)
1550	DAY-AHEAD PRODUCTION COST GUARANTEE RECOVERY DEBIT		$21,117.12
1560	DAY-AHEAD GENERATOR WITHDRAWAL REBATE		$25.12
1650	FORECASTING SERVICE BALANCING AMOUNT		$248.74
9990	IESO ADMINISTRATION CHARGE		$104,216.25
Invoice Total:		$CAD	(2,762,114.44)

Do Not Send Payment

This invoice also constitutes a debit/credit note for GST/HST purposes

Exhibit “H”

IESO Transmission Rights Clearing Account Disbursement webpages

Exhibit “H”

to the Affidavit of Robin Doolittle

Sworn before me on October 29, 2025, in accordance with O. Reg. 431/20,
Administering Oath or Declaration Remotely



Commissioner for Taking Affidavits
(or as may be)

October 29, 2025

Keith Edward Hickey, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.

Expires June 24, 2027.

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Transmission Rights Clearing Account Disbursement

June 7, 2018

Participants withdrawing energy from the IESO-administered market will see a payment from the Transmission Rights Clearing Account disbursement on the May 31 preliminary settlement statement and May 2018 invoice, both to be issued on June 14. Funds from the clearing account will be credited using charge type 102 'TR Clearing Account Credit.'

The total amount of this disbursement will be $100,407,651.79. Market participants will receive their pro-rata share of the total amount based on the total allocated quantity of energy withdrawn (AQEW) for consumers, or the scheduled quantity of energy withdrawn (SQEW) for exporters, over the last six months (December 2017 – May 2018).

Through the transmission rights market in Ontario, the IESO sells transmission rights through an auction process entitling the owner to a payment if the price of energy in Ontario is different from the price in an intertie zone. The Transmission Rights Clearing Account has a threshold set by the IESO Board of Directors and surplus amounts in the account are disbursed over time.

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Transmission Rights Clearing Account Disbursement

December 6, 2018

Participants withdrawing energy from the IESO-administered market will see a payment from the Transmission Rights Clearing Account on the November 30 preliminary settlement statement and November 2018 invoice, both of which will be issued on December 14. Funds from the clearing account will be credited using charge type 102 TR Clearing Account Credit.

The total amount of this disbursement will be $87,291,613.97. Market participants will receive their pro-rata share of the total amount based on the total allocated quantity of energy withdrawn (AQEW) for consumers, or the scheduled quantity of energy withdrawn (SQEW) for exporters, over the last six months (June 2018 – November 2018).

The IESO sells transmission rights through an auction process entitling the owner to a payment if the price of energy in Ontario is different from the price in an intertie zone. The Transmission Rights Clearing Account has a threshold set by the IESO Board of Directors and surplus amounts in the account are disbursed over time.

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Transmission rights clearing account disbursement

June 6, 2019

Participants withdrawing energy from the IESO-administered market will see a payment from the transmission rights clearing account on the May 31 preliminary settlement statement and the May 2019 invoice, both of which will be issued on June 14. Funds from the clearing account will be credited using charge type 102, TR Clearing Account Credit.

The total amount of this disbursement will be $76,406,085.16. Market participants will receive their pro-rata share based on the total allocated quantity of energy withdrawn for consumers, or the scheduled quantity of energy withdrawn for exporters, over the six months ending May 2019.

The IESO sells transmission rights through an auction process entitling the owner to a payment, if the price of energy in Ontario is different from the price in an intertie zone. The transmission rights clearing account has a threshold set by the IESO Board of Directors and surplus amounts in the account are disbursed over time.

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Transmission rights clearing account disbursement

December 5, 2019

Participants withdrawing energy from the IESO-administered markets will see a payment from the transmission rights clearing account disbursement on the November 30 preliminary settlement statement and November 2019 invoice, both issued on December 13. Funds from the clearing account will be credited using charge type 102 TR Clearing Account Credit.

The total amount of this disbursement will be $72,451,505.15. Market participants will receive their pro-rata share of the total amount based on the total allocated quantity of energy withdrawn (AQEW) for consumers, or the scheduled quantity of energy withdrawn (SQEW) for exporters, over the last six months (June 2019 - November 2019).

See more information on the transmission rights market.

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Transmission rights clearing account disbursement

June 4, 2020

Participants withdrawing energy from the IESO-administered market will see a payment from the transmission rights clearing account disbursement on the May 31 preliminary settlement statement and May 2020 invoice, both issued on June 12. Funds from the clearing account will be credited using charge type 102 TR Clearing Account Credit.

The total amount of this disbursement will be $59,225,634.30. Market participants will receive their pro-rata share of the total amount based on the total allocated quantity of energy withdrawn (AQEW) for consumers, or the scheduled quantity of energy withdrawn (SQEW) for exporters, over the last six months (December 2019 - May 2020).

See more information on the transmission rights market.

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Transmission Rights Clearing Account Disbursement

December 3, 2020

Participants withdrawing energy from the IESO-administered market will see a payment from the transmission rights clearing account disbursement on the November 30 preliminary settlement statement and November 2020 invoice, both issued on December 14. Funds from the clearing account will be credited using charge type 102 TR Clearing Account Credit.

The total amount of this disbursement will be $58,649,176.39. Market participants will receive their pro-rata share of the total amount based on the total allocated quantity of energy withdrawn for consumers, or the scheduled quantity of energy for exporters, over the last six months (June 2020 - November 2020).

More information is available on the transmission rights market web page.

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Transmission Rights Clearing Account Disbursement

June 3, 2021

Participants withdrawing energy from the IESO-administered market will see a payment from the Transmission Rights Clearing Account (TRCA) on the May 31 preliminary settlement statement and May 2021 invoice, both issued on June 14. Funds from the clearing account will be credited using charge type 102 'TR Clearing Account Credit'.

The total amount of this disbursement will be $44,323,525.92 and will be split into two classes – loads and exporters. This disbursement will be split based on the proportion of total provincial transmission service charges and total export transmission service charges collected from the market between Nov 2020 and Apr 2021. The proportion of transmission costs paid over the latest TRCA balance period are: 98.13 per cent for the Provincial Transmission Service Charge, 1.87 per cent for the Export Transmission Service Charge.

Market participants will receive their pro-rata share of funds allocated to their respective class based on the total allocated quantity of energy withdrawn for loads, and the scheduled quantity of energy for exporters, over the last six months (December 2020 – May 2021). More information is available on the transmission rights market web page.

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Transmission Rights Clearing Account Disbursement

December 2, 2021

Participants withdrawing energy from the IESO-administered market will see a payment from the Transmission Rights Clearing Account (TRCA) on the November 30 preliminary settlement statement and November 2021 invoice, to be issued on December 14. Funds from the clearing account will be credited using charge type 102 'TR Clearing Account Credit'.

The total amount of this disbursement will be $53,699,104.98 and will be split into two classes – loads and exporters. This disbursement will be split based on the proportion of total provincial transmission service charges and total export transmission service charges collected from the market between May 2021 and October 2021. The proportion of transmission costs paid over the latest TRCA balance period are: 98.40 per cent for the Provincial Transmission Service Charge, 1.60 per cent for the Export Transmission Service Charge.

Market participants will receive their pro-rata share of funds allocated to their respective class based on the total allocated quantity of energy withdrawn for loads, and the scheduled quantity of energy for exporters, over the last six months (June 2021 to November 2021). More information is available on the Transmission Rights Market web page.

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Transmission Rights Clearing Account Disbursement

June 9, 2022

Participants withdrawing energy from the IESO-administered market will see a payment from the Transmission Rights Clearing Account (TRCA) on the May 31 preliminary settlement statement and May 2022 invoice, to be issued on June 14. Funds from the clearing account will be credited using charge type 102 'TR Clearing Account Credit'.

The total amount of this disbursement will be $70,849,868.72 and will be split into two classes – loads and exporters. This disbursement will be split based on the proportion of total provincial transmission service charges and total export transmission service charges collected from the market between December 2021 and May 2022. The proportion of transmission costs paid over the latest TRCA balance period are: 98.26 per cent for the Provincial Transmission Service Charge, 1.74 per cent for the Export Transmission Service Charge.

Market participants will receive their pro-rata share of funds allocated to their respective class based on the total allocated quantity of energy withdrawn for loads, and the scheduled quantity of energy for exporters, over the last six months (December 2021 to May 2022). More information is available on the Transmission Rights Market web page.

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Transmission Rights Clearing Account Disbursement

December 8, 2022

Participants withdrawing energy from the IESO-administered market will see a payment from the Transmission Rights Clearing Account (TRCA) on the November 30 preliminary settlement statement and November 2022 invoice, to be issued on December 14. Funds from the clearing account will be credited using charge type 102 'TR Clearing Account Credit.'

The total amount of this disbursement will be $131,101,678.45 and will be split into two classes – loads and exporters. This disbursement will be split based on the proportion of total provincial transmission service charges and total export transmission service charges collected from the market between May 2022 and October 2022. The proportion of transmission costs paid over the latest TRCA balance period are: 98.58 per cent for the Provincial Transmission Service Charge, 1.42 per cent for the Export Transmission Service Charge.

Market participants will receive their pro-rata share of funds allocated to their respective class based on the total allocated quantity of energy withdrawn for loads, and the scheduled quantity of energy for exporters, over the last six months (June 2022 to November 2022). More information is available on the Transmission Rights Market web page.

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Transmission Rights Clearing Account Disbursement

June 8, 2023

Participants withdrawing energy from the IESO-administered market will see a payment from the Transmission Rights Clearing Account (TRCA) on the May 31 preliminary settlement statement and May 2023 invoice, to be issued on June 14. Funds from the clearing account will be credited using charge type 102 'TR Clearing Account Credit'.

The total amount of this disbursement will be $114,450,289.06 and will be split into two classes – loads and exporters. This disbursement will be split based on the proportion of total provincial transmission service charges and total export transmission service charges collected from the market between November 2022 and April 2023. The proportion of transmission costs paid over the latest TRCA balance period are: 98.55 per cent for the Provincial Transmission Service Charge, 1.45 per cent for the Export Transmission Service Charge.

Market participants will receive their pro-rata share of funds allocated to their respective class based on the total allocated quantity of energy withdrawn for loads, and the scheduled quantity of energy for exporters, over the last six months (December 2022 to May 2023). More information is available on the Transmission Rights Market web page.

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Transmission Rights Clearing Account Disbursement

December 7, 2023

Participants withdrawing energy from the IESO-administered market will see a payment from the Transmission Rights Clearing Account (TRCA) on their November 30 preliminary settlement statement and November 2023 invoice that will be issued on December 14. Funds from the clearing account will be credited using the charge type 102 'TR Clearing Account Credit'.

The total amount of this disbursement will be $61,274,078.75. It will be split between two classes (loads and exporters) based on the proportion of total provincial transmission service charges and total export transmission service charges collected from the market between May 2023 and October 2023. The proportion of transmission costs paid over the latest TRCA balance period are 98.9 per cent for the Provincial Transmission Service Charge and 1.1 per cent for the Export Transmission Service Charge.

Market Participants will receive their pro-rata share of the funds allocated to their respective class based on the total allocated quantity of energy withdrawn for loads and the scheduled quantity of energy for exporters over the last six months (June 2023 to November 2023). More information is available on the Transmission Rights Market webpage.

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Exhibit "I"

IESO report entitled "Intertie Transaction Failure Guidelines" dated November 18, 2005

Exhibit "I"

to the Affidavit of Robin Doolittle

Sworn before me on October 29, 2025, in accordance with O. Reg. 431/20, Administering Oath or Declaration Remotely



Commissioner for Taking Affidavits
(or as may be)

October 29, 2025

Keith Edward Hickey, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.

Expires June 24, 2027.



REPORT

Intertie Transactions Failures Guidelines

Market Assessment and Compliance Division
18 November 2005

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1. INTRODUCTION

In March 2005 the IESO's Market Assessment and Compliance Division (MACD) established a working group to advise on the effectiveness of its existing guidelines in reducing intertie transaction failures and to provide advice on revised guidelines and the associated market manual. The group's terms of reference are attached as Appendix A.

MACD took this action in light of the continuing problem of significant volumes of inter-jurisdictional energy transactions failing in real-time in the IESO-administered market. As will be apparent later in the report, this is not a problem uniquely associated with traders; however MACD took the view that its enforcement of the market rule provisions dealing with the component of transaction failures perceived as within the control of market participants was not effective and needed review.

The market rules address transaction failures in two provisions. Section 7.5.8A of Chapter 7 of the rules places an obligation on market participants to schedule energy across the intertie in accordance with the relevant interchange schedule. The rules provide for a formula-based penalty if it is determined that there were no 'bona fide and legitimate reasons' for the failure of any such transaction. Section 7.5.8B states that bona fide and legitimate reasons "…include failures caused by actions and circumstances beyond the control of the market participant…" or due to errors or actions by the IESO or external system operator. A separate provision, section 1.3.5 of Market Manual 4.2 identifies errors in the NERC tagging process as a potential breach of the market rules by market participants.[1] NERC tag errors may cause interchange transactions to fail.

MACD's guidelines with respect to intertie failures on the NYISO and MISO interfaces explain the tests it applies to decide whether to investigate for a possible breach of the rules those transaction failures that appear to be under the control of market participants. They identify 'safe harbours' or conditions under which an investigation will normally be discontinued. The guidelines were established to ensure an efficient use of MACD and market participant resources and not unnecessarily restrict electricity trading. There were published to clearly communicate to market participants MACD's enforcement intentions.

The working group was chaired by MACD and composed of representatives of Brascan Energy Marketing Inc., Coral Energy Canada Inc., DTE Energy Trading Inc., HQ Energy Marketing Inc., MACD, Ontario Power Generation Inc., and Powerex Corp. A series of meetings were held to discuss the nature and significance of transaction failures and discuss possible remedies to reduce them. Extensive non-confidential data were made available to provide details on transaction failures across the different interties from several different perspectives.

This report summarizes MACD's key findings. While the report benefits from the insights and observations of the working group, ultimately it is the responsibility of the business unit delegated by the IESO to enforce compliance with the market rules, MACD, to reach decisions on its enforcement approach. In drafting the report, an effort was made to develop and reflect the consensus view of the working group, to the greatest extent possible. The impact of these views is clearly reflected in the policy conclusions described in section 4 of the report. The conclusions also take into consideration the initiatives recently announced by the IESO designed to improve reliability in preparation for summer, 2006

[1] Section 7.7.2 of Chapter 1 of the market rules binds the IESO and market participants to comply with the provisions of market manuals.

The report is organized as follows: the next section provides an overview of the impact of intertie transaction failures on Ontario system reliability and market performance. While both are important, reliability is identified as the primary goal driving enforcement. Section 3 presents summary data on transaction failures over the past two years. It documents that NYISO accounts for more than two-thirds of IESO's transaction failures. The data also reveal that MACD's screening guidelines for New York transaction failures tolerate relatively high failure rates for several market participants.

Section 4 provides a brief summary and conclusions. It considers the salient points of the data and provides the rationale for the resulting policy conclusions. These relate to clarifications of MACD's screening guidelines for both the NYISO and MISO markets, more stringent conditions on supply tight days and identification of a means to make the treatment of market participant intertie failures market-based without the stigma of rule breaches. Finally, in addition to the main body of the report, there are a number of appendices providing more detailed information.

2. SYSTEM AND MARKET IMPACTS OF TRANSACTION FAILURES

Market Efficiency

As noted in successive reports of the Market Surveillance Panel, failed intertie transactions are a contributing factor to distorted market signals exemplified by the persistent price discrepancy between pre-dispatch and real-time prices.[2] As an input to the Working Group deliberations MACD conducted a study to give a sense of the contribution of failed transactions to change in real time price. The study simulates the impact on the real-time market clearing price had transactions failures not occurred in subsets of randomly selected days over the period August 2003 to April 2005. It provides an illustration of the impact of failures due to NERC tag errors or uneconomic bids. The methodology and findings are summarized in Appendices B to D.

Though the working group members agreed that transaction failures contribute to price discrepancy between pre-dispatch and real time price, they felt the analysis did not accurately capture the proportion of this contribution relative to other contributions. They recommended further work before attempting to draw policy conclusions. MACD undertook to continue to refine its analysis, subject to conflicting priorities in its work program. Because of the primordial importance accorded system reliability, as described below, MACD was reluctant to delay the release of this report pending the completion of this work.

System Reliability

The IESO plans generation and dispatchable load commitment to ensure system adequacy and reliability. These plans take into consideration the scheduled intertie trades. With little advance notice of import failures the IESO is often limited in its options to recover from failures and has limited time to assess the reliability impacts of the failures and the impacts of the actions required to replace the failed transactions. Due to the timing of intertie failures the market is unable to solve for deficiencies that have been created as a result of the import failures. In general the reliability impacts of transaction failures fall into 3 categories:

[2] The MSP's latest report released June 2005 describes this on pages 34-35.

Energy and Capacity

Generators are not committed in anticipation of failures and some of these generators have start up lead times that exceed the time provided after failed transactions. Depending on the depth and makeup of the spare offers in the stack this can result in operating reserve and energy deficiencies. Repeated reserve deficiencies are not looked at favourably by Ontario's interconnected neighbours. There is also the added effect of increasing the frequency and duration of scheduling Control Action Operating Reserve (CAOR). Depending on the duration and extent of the reserve deficiencies emergency purchases (if available) will be required to recover and maintain operating reserve.

When additional quick start resources are activated to make up for import failures it can create a situation where energy limited resources that were needed later in the day are scheduled earlier than expected. This can create energy deficiencies in the hours where the energy was originally expected to operate. This occurs most often in the prefreshet period, when forebays have been drawn to minimum in anticipation of freshet and there is limited flexibility in hydroelectric resources, and also during the summer months when the hydroelectric inflows are normally low. These impacts create the requirement to rely more on emergency control actions such as purchasing Emergency Energy and implementing voltage reductions to manage energy deficiencies.

On the other hand, export failures during periods of excess generation may also create excess base-load generation (EBG) problems and could result in area control error (ACE) management issues. Reliability issues may also develop as exports are failed and units have to be decommitted to manage the over generation. With many units having minimum turn around times this can create situations where for example units are shut down in the overnight period and are therefore unavailable to be back on line in time to provide ramp capability during the morning pick up period.

Operating Security Limits (OSL)

The dispatch solution is based on the expectation that scheduled transactions will flow. The dispatch tool compensates for counter flow effects when calculating OSL impacts. Transaction failures can create OSL violations when the transactions that were scheduled fail and interface and or other OSL's were depending on those transactions to operate within the limit. This can result in the need to curtail other transactions to manage the impact (i.e. if an import failed, an export on the same interface may need to be curtailed). These failures can also have the effect of causing the net intertie schedule limit to be exceeded as this limit is based on the net of transactions.

Closing Comments on System Reliability

Intertie failures result in three types of reliability disturbances, namely, energy deficiencies, capacity deficiencies, and operating security limit violations. This creates a greater reliance on emergency control actions such as emergency energy purchases and implementation of voltage reductions to cope with these disturbances. Chronic transaction failures near real-time leave insufficient time to respond reliably.

In September 2005 the IESO's Chief Operating Officer, Paul Murphy, announced several measures that would be introduced to improve reliability.[3] He observed: "[t]he Ontario power system cannot consistently be in an emergency operating state as it was in the summer 2005". Mr. Murphy identified a number of contributing factors, including the failure of import transactions to Ontario. He noted that

[3] See http://www.ieso.ca/imoweb/pubs/consult/dayAhead/da_20050920_operation_reliability.pdf

"Import failures:

- are equivalent to suddenly losing a large generator;
- happen at the last minute;
- occurred almost every day this summer;
- aggravated energy shortage; and
- consistently contributed to the need to enter an emergency operating state"

Among the initiatives announced by Mr. Murphy was an implementation of a day ahead mechanism to allow imports to be guaranteed their offer price in an attempt to ensure real time delivery similar to financial commitments made in neighbouring markets. The policy proposals introduced in section 4 is meant to be consistent with this initiative.

Enforcement Drivers

The Working Group asked MACD to state its primary goal in developing its enforcement policy regarding intertie transaction failures. As system operator, the IESO's primary responsibility is to maintain system reliability. This view shapes the policy recommendations contained in the final section of the report and supports a more effective application of the rules vis-à-vis intertie transaction failures within the control of market participants. However, the effect that transaction failures have on market efficiency issues (pre-dispatch to real time price difference) need to be considered when selecting a solution in spite of the lack of specific quantification of those caused by reasons under the control of market participants. The sheer volume of transaction failures due to market participant actions on all interfaces is 31% (Appendix F), hence, MACD feels addressing transaction failure under participant control is of value in addressing efficiency issues created by transaction failures.

3. DATA ON TRANSACTION FAILURES

The data provided to the working group initially covered the period August 1, 2003 to February 28, 2005. As work progressed the data series was updated to July 31, 2005 so the information now covers two years of operations. It identifies, by month, the difference in MWh and number of transactions between the one hour ahead pre-dispatch constrained schedule and what actually flowed in real-time. A list of the initial data series reviewed by the working group is found in Appendix E.

The various causes for transaction failures have been classified for the purposes of this report into two major categories: scheduling errors that are attributable to trader actions and those that are system operator initiated actions. Those in the first category are economic and NERC tag errors. Those in the second category are external security, internal TLRs, external TLRs, and other.[4]

The purpose of developing the comprehensive data set was for all parties to understand the magnitude, frequency and source of transaction failures. The working group's focus related to the usefulness of MACD's guidelines for enforcing the market rule provisions related to transaction failure; however, it

[4] "Other" refers to failures caused by reasons not attributable to market participant actions such as export cuts due to adequacy or IESO scheduling errors.

was recognized that the enforcement policy needed to take into consideration the relative importance of the various causes of transaction failures and parallel work by the IESO to address them.

The key facts about the intertie failures experienced in Ontario are as follows:

New York Independent System Operator

- The NYISO interface accounts for the largest share of total system transaction failures, both in terms of failures for all reasons, and in terms of only those failures due to uneconomic bids and tag errors. Between August 1, 2003 and July 31, 2005, 71% of the total MWh of transaction failures over all interfaces were with NYISO (Appendix F - Table F). 31% of total system failures were due to uneconomic bids and tag errors, 84% of which occurred over the NYISO interface.

- Over the period under review the volume of exports from Ontario to NYISO was almost seven times that of imports; however, the failure rate[5] for imports was slightly higher compared to exports – 12% versus 11% (Appendix F - Table A). These represent failures for all reasons.

- In terms of failures due solely to uneconomic trades or NERC tag errors, the import failure rate at 7.46% was double that of exports (3.68%) (Appendix F –Table A). In other words, even though significantly more trade flowed as an export, market participants were less successful in navigating the NYISO market when importing.[6] In fact these 'economic' and tag error failures constituted the dominant segment of import failures with NYISO in almost every month, accounting for about 60% of MWh failures over the period (Appendix F - Table B).

- Causes other than uneconomic bids or NERC tag errors account for a significant proportion of total NYISO transaction failures, especially with respect to exports.[7] On average 66% of monthly export transaction failures are attributable to these other causes, the largest share being external security (53%). External security was the cause of almost a quarter of total MWh import failures over the period, with smaller fractions attributable to the other causes (Appendix F - Table B).

- The application of MACD's guidelines for the NYISO market eliminated from further investigation a relatively large share of the total MWh that failed because of uneconomic bids. While a high number of transaction failures and market participants were screened in after the first test, by the time the third test was applied very few, if any, MWh of failures were left. This allowed several participants to maintain relatively high failure rates over the period.

    - As a result of the first test, on average 75% of MWh associated with economic failures were screened in for review.[8] After applying the second criteria, the volatility test, the percentage of MWh in each month subject to further review dropped. On average 48% of

[5] The failure rate is the MWh of failures expressed as a percentage of the total MWh scheduled in the one hour ahead pre-dispatch.
[6] These failure rates increased during the 6-month period of the working group deliberation.
[7] External security, external TLR, internal TLR and 'other'.
[8] This percentage is the MWh of failed transactions with NYISO that failed the first test divided by the total MWh of transactions with NYISO that failed due to uneconomic bids or NERC tag errors.

MWh of these transactions failures were left for further review. When all three safe harbours were applied, on average only 2% of all the MWh that failed due to uneconomic trades were eligible to be investigated as a breach (Appendix F - Table C).

- Finally, considering economic transaction failures in NYISO on a stand-alone basis, on average 37% of these failures occurred in volatile hours over the period (Appendix F - Table E). In other words, this measure of volatility figured as an important safe harbour during the period.

- There is a wide variation in average failure rates, between zero and 38%, among market participants trading on the New York interface who failed for economic reasons.[9]

- Eleven market participants had two year average failure rates greater than 5%. Of the eleven, three had scheduled trading volumes of less than 100,000 MWh over the period (August 2003 – July 2005). The rest had substantial volumes, including two with more than 1 TWh of scheduled trading over the period. These eleven organizations account for 86% of all the New York economic failures and 61% of the traded volume on the NYISO interface for the period.

- Eight of the 22 market participants had average failures rates lower than 3% over the two-year period. Four market participants had relatively high scheduled trading volumes in excess of 500,000 MWh and one just under 2 TWh. The remaining four had trading volumes below 100,000 MWh with failure rates around 1% or below. These eight organizations account for 6% of all the New York economic failures and 20% of the traded volume on the NYISO interface for the period.

- Eight percent of all New York economic failures and 19% of New York traded volume was conducted by three market participants with failure rates between 3% and 5%. Of these three organizations, one traded over 2 TWh for the period.

- The same performance analysis was conducted using the historical failure rate in Appendix G (second bar).[10] Trading organizations with historical failure rates greater than 5% contributed 57% of economic failures and 32% of trade on the interface. Market participants with historical failure rates between 3% and 5% accounted for 29% of economic failures and 29% of trade on the interface. Those with historical failure rates of less than 3% were responsible for 13% of economic failures and 39% of trade. Similarly, small trading organizations (less than 100,000 MWh) and large trading organizations (greater than 1 TWh) occupy each performance range.

- In summary, the ability to successfully navigate the New York interface does not seem to be linked to the volume of trade of an organization. Both small and large traders have been able to achieve relatively low failure rates.

[9] See Appendix G. The period covered is from August 1, 2003 to July 31, 2005. Of the 25 market participants, numbers 4, 6, and 10 as denoted in Appendix G, are not included in the performance ranges because they were not actively trading.

[10] Historical failure rate is calculated for each organization as follows: total MWh volume failed in New York market divided by the total MWh volume traded in New York market. The rate was calculated for the two year period of August 2003 to July 2005. The average failure rates reported earlier were the averages of the 30 day rolling failure rates, used in the guidelines, for the same 2-year period.

Midwest Independent System Operator & Other Interfaces

The opening of the MISO market April 1, 2005 changed some of the parameters of trade with Ontario. The summaries below are based on data before these changes.

- Michigan and NYISO are Ontario's two most important interjurisdictional trading interfaces.
- In terms of transaction failures, after NYISO, the Michigan interface is the second most important source of failures although it was a distant second with only 24% of total MWh failures over the period August 2003 – August 2005 (Appendix F – Table F).
- Over the period under review the volume of imports to Ontario from Michigan was roughly 16 times that of exports; however, the export failure rate of 9% was over double the failure rate for imports.[11] (Appendix F – Table A)
- The principal reason for both import and export failures in almost all months was Transmission Loading Relief in the Michigan control area. On average external TLRs represented about 70% of MWh export failures and 74% of MWh import failures (Appendix F – Table B).
- Manitoba, Minnesota and Quebec are responsible for only small fractions of transaction failures with Ontario (Appendix F - Table F).

While the working group was not shown transaction data for the MISO interface post April 2005, we note that over the period April 1 – September 30, 2005 the rate of import failures has increased to the point that it almost equals the export failure rate - 7.8% imports vs. 8.7% exports.

Supply Tight Days and Recurrent Failures

Market participants frequently fail more than one transaction because of either uneconomic trades or NERC tag errors during supply tight days, defined as when an Energy Emergency Alert (EEA) had been declared by the IESO. At times these failures occurred during volatile hours however, there are recurrent[12] and consecutive[13] failures that also occur during stable hours when an EEA has been declared. Recurrent and consecutive failures were also observed outside of the period of EEA declaration within the same day.

Of the eighteen days examined, 13 (72%) had transactions where the same market participant failed on economic grounds for three or more consecutive hours.[14] 72% of the days experienced failures during the hours the EEA was declared. Ten days (56%) had failures occurring in both volatile and stable hours. Import failures were observed twice as often as export failures.

Further analysis of market participant recurrent behaviour was also conducted outside of the days defined as supply tight. Recurrent economic failures within a day by market participants were

[11] Calculated the same way as explained earlier for NYISO.
[12] Recurrent failures are defined as three or more transaction failures which occur in the same day for the same reasons (tagging or economic grounds) by the same market participant.
[13] Consecutive failures are defined as failures observed in three or more consecutive hours for the same reasons by the same market participant.
[14] April 2 was removed from the supply tight day analysis because of the opening of the MISO market. This day had a high number of recurrent tagging failures.

examined.[15] Of the 696 days examined, 181 days (26%) contained one trading organization that failed three or more economic trades during a day (Appendix H).[16] Approximately 62% of the days examined contained at least one market participant that failed recurrently on economic grounds.

Recurrent NERC tagging failures within a day by individual trading organizations on days outside of those defined as supply tight were examined.[17] Of the 696 days examined, 193 days (28%) contained one trading organization that failed two or more tagging failures during a day (Appendix I). Approximately 41% of the days examined contained at least one market participant organization which recurrently failed on tagging grounds.

4. POLICY CONCLUSIONS

Overview of Changes

We propose two changes to the existing enforcement of the market rules related to intertie transaction failures viewed as within the control of market participants. The first is to make the tests contained in MACD's screening guidelines for the NYISO and Midwest ISO markets more stringent for import failures during supply tight days.

The second, more fundamental proposal, is to no longer treat transaction failures as a compliance matter, except where there appears to be egregious behaviour. Rather, as part of the settlement process, a market participant would compensate the market for transaction failures that are deemed to be under its control. This would require a rule change to remove the formula-based penalty. Potential egregious conduct associated with transaction failures would lead to the normal compliance investigation if it is alleged that the market participant unfairly benefited from transmission rights payments, CMSC or other revenues.

The proposals are described in more detail below after explaining their rationale.

Rationale for Proposals

New York Economic Guideline Changes

In our view, if considered in isolation, the data provided to the working group and summarized in sections 3 of this report justify a tightening of the NYISO guidelines. For the last two years the largest share of transaction failures is at the NYISO interface. Many of these failures, particularly exports from Ontario to New York, are for reasons that are traditionally viewed as outside the control of market participants. At the same time a significant volume of failed transactions result from uneconomic bids or offers by market participants in the NYISO market[18]. A review of the record of MACD's NYISO guidelines demonstrates that, as presently structured, few MWh are selected for investigation and some market participants have relatively high failure rates. The guidelines also do not effectively screen in for

[15] Recurrent failures on economic grounds are defined as three or more within the same day by the same market participant.
[16] Study period was from August 1, 2003 to June 26, 2005 and excluded days when EEA alerts were declared.
[17] Recurrent failures due to NERC tagging are defined as two or more within one day.
[18] It may be possible to change the IESO-NYISO scheduling protocols to reduce the number of intertie transactions scheduled that will likely fail. The working group was briefed on the efforts by the system operators in this regard but, at the time of this report, there was no information as to whether such changes were feasible.

further investigation participants who fail transactions during supply tight periods or for other reliability related issues.

However, in light of the unanimous opposition expressed by the working group to our earlier proposed changes to the NYISO guidelines, the broad support for a new approach to the treatment of real-time transaction failures and the opportunity to implement these changes coincident with day-ahead proposals, we have decided not to substantially change the guidelines at this time. Rather, other than the supply tight days mechanism described below, MACD will maintain the status quo recognizing that if the settlement based solution for curbing transaction failures is not implemented more extensive guideline changes will be required.

Supply Tight Days (Energy and Capacity Shortfalls)

From a reliability perspective transaction failures occurring on supply tight days are serious. The data summarized in section 3 documents that there is a very high incidence of consecutive and recurrent transaction failure on the NYISO interface and import failures occurred twice as often as export failures. While no separate data was reported for the MISO interface with Ontario, the direct link of import failures to energy and capacity shortfalls and the fact that import failures from MISO have increased significantly since MISO's market opening in April 2005, in our view also justifies a more stringent review of MISO failures on these supply tight days. Most working group members generally accepted this logic but asked that market participants be given adequate notice before the usual screening tests are tightened for imports. We believe that our proposal addresses this concern. Clearly, this proposal is only a partial answer to reliability concerns, but we feel it is an appropriate interim addition until the settlement proposal can be adopted.

The implications for transaction failures of MISO policies and procedures with respect to the acquisition of ramp and transmission service needs further study; however, we do not wish to delay the release of this report. For now the only change of substance in the MISO guidelines would be related to supply tight days. However, the revision to the MISO guidelines will give an opportunity to clarify that the existing screen applies not just to the Michigan interface and that the guidelines are used to screen both potential breaches of NERC tagging requirements and Chapter 7, section 7.5.8A. This has always been our view but the guidelines would benefit from an edit to introduce clearer language and address new issues that have arisen since they were released two years ago.

Settlement Proposal

The attractiveness of the settlement proposal is that it would remove the stigma associated with market rule breaches and the related administrative burden on market participants and MACD in reviewing and remedying alleged breaches. Transaction failures would no longer be 'compliance' issues; rather market participants would have an incentive to ensure that they navigate the neighbouring markets successfully by virtue of a settlement charge for their failed transactions deemed within their control. The cost of this would vary depending on the market circumstances, so that one would expect the charge to rise during times when the Ontario market is supply tight.

From a conceptual point of view, we see this market-based approach as much more desirable than the current regulatory scheme where there is a natural incentive for market participants to adjust their trading strategy to conform to whatever precepts are advanced by the regulator, in this case MACD. This report documents how MACD's current enforcement approach has tolerated significant volumes of intertie energy transactions to fail and allowed individual market participant failure rates to be as high as 38%. The risk of a significantly more stringent regulatory approach is that it may lower transaction

failures but at the cost of lost trade. MACD joins with the majority of working group members who support developing a more market-oriented approach to addressing transaction failures, as along the lines of what is outlined below.

With the implementation of such an approach coincident with, and complementary to, the proposed arrangements to protect system reliability for summer 2006, we believe there still needs to be some form of compliance safety net to address potential abuses by market participants related to CMSC transmission rights payments, or other revenues. This was not a matter put forward for consideration by the working group members and it would need to be the subject of future discussions with market participants.

The Proposals

Guideline Changes

The content of the guidelines for both NYISO and the Midwest ISO will not change except in the following respect: During reliability related events as declared through System Status Reports (SSR), the safe harbours in the guidelines will not be available to market participants whose imports fail on economic grounds three or more times during the period of the emergency declaration. The third and subsequent failures will proceed directly to compliance investigation. The specific communication trigger through SSR is yet to be determined. The latter applies to those transactions that fail in the hour which starts at least two hours and 30 minutes after the declared reliability event. The market participant can bring forward information regarding insufficient notification which affected their ability to have avoided the third or subsequent failures; this will be considered in the compliance case review.

The revision of the guidelines to incorporate the above-described change also affords an opportunity to clarify the inherent discretion to suspend the normal guidelines on a participant-specific basis, for example, if the participant's failure rate remains unacceptably high or if there are grounds to believe gaming or other abuses to the rules are taking place. In addition, specifically with respect to the Midwest ISO, the revised MISO guidelines will clarify that the existing screen applies not just to the Michigan interface and that the guidelines are used to screen both potential breaches of NERC tagging requirements and Chapter 7, section 7.5.8A

Settlement Proposal

Removal of all Compliance Screens and Changes to Formula-Based Penalty of Chapter 6 section 6.610A

With the implementation of a settlement solution described below, there would no longer be compliance enforcement of transaction failures and the guidelines for the MISO and New York interfaces would cease to have effect.

At present the penalty formula for 7.5.8A breaches is prescribed in Chapter 6 section 6.6.10A as the maximum of HOEP or the absolute value of (HOEP- offer / bid) x Multiplier. The latter penalty formula would be replaced with a formula for a settlement amount which will apply to all import and export transactions failures that do not fail for "bona fide or legitimate reasons". The application of this formula will be considered a settlement amount and not a penalty applied through the compliance process in Chapter 3 section 6. As such, there would be no breach of the market rules for public posting on the IESO web site. The deterrence is contained in the continual risk imposed by the application of the settlement amount. The below formulas provides some indication of the general construct of the penalty or

application trigger. The precise implementation, application trigger, and settlement amount formula would require further stakeholder consultation.

> Settlement Amount for Exports Failures = {Max [0, (Pre-dispatch Zonal Price – Real Time Zonal Price)] x MWh failed}
>
> Settlement Amount for Import Failures = {Max [0, (Real Time Zonal Price – Pre-dispatch Zonal Price)] x MWh failed}

MACD would reserve the right to exercise the compliance process and apply a penalty in addition to the settlement amount if it is found that a market participant used transaction failures to unjustly acquire market revenues. This ability to recover monies gained presently exists through the application of a multiplier to the formula-based penalty, however, the ability of MACD to recover the monies gained will continue. The multiplier has been removed from the settlement formula amount.

5. VIEWS OF WORKING GROUP MEMBERS

This report is heavily based on the active and constructive advice of working group members throughout the exercise. We would like to acknowledge their efforts and express our appreciation. Their written comments on an earlier draft of this report will be posted in full.

As already noted we have elected to pull back from a radical overhaul of the NYISO guidelines, at this time, in the face of the universal concerns of working group members regarding an earlier draft proposal and advocacy for a settlement option. , Three members stated that the supply tight days proposal was 'reasonable' or words to that effect and we have elected to proceed with this change. Powerex and HQ Energy Marketing oppose compliance enforcement as a remedy for intertie failures, except "truly abusive market behaviour" (HQ Energy Marketing). As noted below in our response to Powerex, such an interpretation is simply at odds with a plain reading of the market rules.

With respect to the settlement proposal it is worth briefly quoting the views of four market members of the working group because they constitute a strong endorsement:

<u>Brascan</u>

> "We believe that option #3 [the settlement option] is a good long-term solution that provides the correct market-based incentives to drive appropriate market participant behaviour. This option provides a direct link between an intertie trader's actions and their affect on the market. We believe implementation of this option will improve the accuracy of pre-dispatch prices, increase use of the transmission system and help protect system reliability."

<u>Coral</u>

> "Coral agrees with MACD's strong support for a market-oriented approach to addressing transaction failures. Further efforts should be dedicated towards discussion, design, and implementation of a formulaic approach, as described in Proposal 3 that provides the appropriate and proportional disincentive for failures during times when our reliability is most at risk."

DTE Energy Trading

> "DTE ET strongly supports a market-based solution to intertie failure administration as detailed in 'Proposal 3'. DTE ET does realize that there is a lot of work to do in order to put forth an acceptable 'to the market' solution/alternative to the current or revised guidelines set forth by the IESO MACD to address intertie failures. Thus, DTE ET will not present comment on Proposal 3 at this time, other than to reiterate its support for such a proposal. DTE ET commits to remaining on the ITFWG [Intertie Transactions Failure Working Group] and assisting in reaching an acceptable market based solution for MACD and other Market Participants."

OPG

> "OPG is in favour of Proposal 3. We think that market based solutions and payments for damages are preferable to regulations, breaches and penalties as have been used to date. While we cannot endorse any specific proposal at this time without further study, we feel that the almost unanimous support of the subcommittee behind such proposals make the development of an acceptable proposal in time for spring implementation to be quite probable. We strongly suggest that the subcommittee be used to work with you to develop an acceptable proposal ASAP."

The remaining members of the working group, Powerex and HQ Energy Marketing pointed to trading 'seams' issues and market design as the principal causes of intertie failures. Both spoke against more stringent compliance enforcement but did not comment specifically on the settlement proposal. Powerex commented as follows:

Powerex

> "As an active participant in the Ontario market, particularly in the Inter-jurisdictional markets, Powerex is very concerned over the direction MACD has taken with its [draft] recommendations and interpretation of 'failures within the control of market participants.' It is Powerex's opinion that Compliance penalties are meant to penalize market abuse behaviours, Inter-jurisdictional transactions which fail due to economics or physical scheduling limitations such as ramp constraints in neighbouring regions reflect 'Seams issues' (ie: different markets clearing at different times) and fundamental market design problems and should not be addressed with a compliance program but via Market Design reform.
>
> …Powerex believes the suggested impact on market performance of those intertie failures which are arguably the result of seams failures is not compelling, particularly as the proposed guidelines will further restrict the potential for the market participants to respond to price divergence between markets.
>
> We believe that MACD should remain with the status quo until there can be a review of Inter-jurisdictional Trade within broader discussion around market design and addressing seams issues."

We accept Powerex's observation on the role of seams issues as a source of intertie failures. And the working group was updated on the status of IESO discussions with representatives of NYISO and the Midwest ISO. Members of the working group also made specific suggestions to the IESO representatives involved in those discussions on changes to the scheduling protocols that might alleviate the failures. But ultimately the working group's mandate was focussed on MACD's compliance responsibilities.

We respectfully disagree with Powerex's observation that "…Compliance penalties are meant to penalize market abuse behaviours…", apparently to the exclusion of all other rationales. Simply put, the vast majority of market rule obligations in Ontario and other electricity markets are needed for the complex system of real-time electricity production and consumption to work. Compliance enforcement operates in the background to ensure the many players with different roles and responsibilities work together effectively. There are provisions in Ontario's market rules that address market abuse or egregious behaviour, but these are the exception, not the rule.

HQ Energy Marketing noted that "… we fail to see any convincing evidence regarding a direct link between failed intertie transactions and energy prices." It also observed that:

> "The current IESO market design, including its two hour ahead bidding requirements, leave it out of sync with all the other energy markets in the Northeast. IESO's guidelines simply emphasize this existing disparity. The IESO actually acknowledged this inefficiency by moving from the original four hour ahead bidding requirements. It resulted in significant improvements but there is still unfinished business here.
>
> HQEM suggest the IESO should address this underlying root cause of the problems being experienced instead of implementing new guidelines that will only exacerbate existing market issues."

In response to the call to address seams issues we reiterate our comments above and also observe that MACD feels a responsibility to move to a more immediate solution then is likely from a re-design that will require the active participation and concurrence of other jurisdictions and their market participants. Finally, we note that contrary to HQ Energy Marketing's view, there is convincing evidence of a direct link between failed transactions and energy prices. The point of disagreement is on the magnitude of the impact, an issue we intend to study further as time and other priorities permit. We do not view this as a priority matter at this time because, as stated explicitly in our report (section 2, page 6), the driver for change is the critical state of reliability in the Ontario system.

6. NEXT STEPS

The need to stakeholder the settlement solution provides an opportunity to coordinate with development of the Day Ahead Commitment initiatives. MACD is committed to collaborating with the working group members and other market participants to achieve this end. We expect to do this within the consultative structures and timetable established by the IESO's Market Evolution group; the Intertie Transactions Failure Working Group, as such, has fulfilled its mandate.

With respect to the revised guidelines presented in section 5, MACD plans to release draft documents, as time permits, in the next several weeks.

NEXUS ENERGY INC. -and-	INDEPENDENT ELECTRICITY SYSTEM OPERATOR (IESO)
Applicant	Respondent

IN THE MATTER OF an Arbitration under Chapter 3 of the IESO Market Rules made pursuant to section 32 of the Ontario *Electricity Act, 1998*, S.O. 1998, c. 15, as amended

MEMORIAL OF THE APPLICANT,
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VOLUME ONE

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B E T W E E N:

NEXUS ENERGY INC.

Applicant

- and -

INDEPENDENT ELECTRICITY SYSTEM OPERATOR (IESO)

Respondent

MEMORIAL OF THE APPLICANT, NEXUS ENERGY INC.

VOLUME TWO

October 31, 2025

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IESO's Market Rule Amendment Proposals: MR-00308-R00 to MR-00308-R04

Exhibit “J”

to the Affidavit of Robin Doolittle

Sworn before me on October 29, 2025, in accordance with O. Reg. 431/20, Administering Oath or Declaration Remotely



Commissioner for Taking Affidavits
(or as may be)

October 29, 2025

Keith Edward Hickey, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.

Expires June 24, 2027.

Market Rule Amendment Proposal

PART 1 – MARKET RULE INFORMATION

Identification No.:	MR-00308-R00			
Subject:	Intertie Transactions			
Title:	Settlement Charges for Real-Time Intertie Transaction Failures			
Nature of Proposal:	☒ Alteration	☐ Deletion	☐ Addition	
Chapter:	3	Appendix:	3.1	
Sections:	6.6			
Sub-sections proposed for amending:	6.6.10A, 6.6.10B and 6.6.10C			

PART 2 – PROPOSAL HISTORY

Version	Reason for Issuing	Version Date
1.0	Submit for Technical Panel Review	January 5, 2006
2.0	Publish for Stakeholder Review and Comment	January 12, 2006
3.0	Submit for Technical Panel Review and Vote	January 18, 2006
4.0	Recommended by Technical Panel and Submitted for IESO Board Approval	January 25, 2006
5.0	Approved by IESO Board	February 3, 2006

Approved Amendment Publication Date:	February 7, 2006
Approved Amendment Effective Date:	June 1,2006

PART 3 – EXPLANATION FOR PROPOSED AMENDMENT

Provide a brief description of the following:

- The reason for the proposed amendment and the impact on the *IESO-administered markets* if the amendment is not made.
- Alternative solutions considered.
- The proposed amendment, how the amendment addresses the above reason and impact of the proposed amendment on the *IESO-administered markets*.

Summary

It is proposed to amend the market rules to no longer treat intertie transaction failures as a compliance matter, except in the case of egregious behaviour. Instead, it is proposed that as part of the settlement process, the market participant would be assessed a new charge, called an "import/export failure charge", that would compensate the market for intertie transaction failures that fail for reasons that are not "bona fide and legitimate" (which as defined in the market rules largely include reasons that are beyond the control of the market participant). Where a transaction fails for bona fide and legitimate reasons, the failure charge would not be assessed. However, where egregious behaviour has occurred, the amended compliance rules would allow compliance actions to be taken to recover settlement amounts (such as transmission rights payments, congestion management settlement credits or other settlement amounts) that were made to the market participant as a result of that behaviour.

With the settlement charge acting as a deterrent, the incidence of intertie transaction failures is expected to decline under this revised approach for the treatment of intertie transaction failures. Amendments are proposed to the compliance provisions in Chapter 3, to the provisions relating to compliance with dispatch instructions in Chapter 7, to a provision relating to the transmission rights clearing account in Chapter 8, and to the settlement provisions of Chapter 9.

The compliance provisions of Chapter 3 would be amended to remove the present formulaic penalty provision. This would be replaced by an import/export failure charge that is separate from the compliance construct of Chapter 3. This settlement provision would have market participants compensate the market for deviations from their intertie transaction schedules. For circumstances of egregious behaviour where payment recovery is appropriate and presently made through the formula based penalty, a specific provision would be added to enable the adjustment of settlement amounts. Chapter 7, section 7.5.8B, Compliance with Dispatch Instructions would be amended to allow for the application of the new settlement provisions. Chapter 8, section 4.18 would be amended to allow for the return to the transmission rights clearing account of payments that were inappropriately paid to a market participant.

The settlement provisions of Chapter 9 would be amended to set out the new intertie transaction settlement charges and their disposition to the hourly uplift or to the monthly non-hourly uplift until such time as the IESO has the software capability to allocate the revenue received from these charges to the hourly uplift.

This amendment also proposes that all references to the IMO in Chapters 3, 7, 8 and 9 and in the appendix of Chapter 3 be changed to IESO to align the market rules with the corporation name change under Bill 100.

Background

Significant volumes of inter-jurisdictional energy transactions are failing in real-time in the IESO-administered market (i.e. transactions scheduled in the hour ahead pre-dispatch schedule are failing to

PART 3 – EXPLANATION FOR PROPOSED AMENDMENT

materialize in the real-time dispatch schedule). As a result of these ongoing failures, the Market Assessment and Compliance Division (MACD) is of the view that its enforcement of the market rule provisions dealing with the component of transaction failures, perceived to be within the control of market participants has not been effective and needed review. An IESO stakeholder working group was established in March 2005 to exchange information and to obtain the views of stakeholders. Following a series of meetings to discuss the nature and significance of transaction failures and to discuss possible remedies to reduce them, MACD prepared a report with its findings that is at the following web location:
http://www.theimo.com/imoweb/pubs/consult/intertieTrading/itfwg_2005nov23_Report.pdf

See also the corresponding rule amendment submission, MR-00308-Q00 to this rule amendment proposal document.

The existing market rules address transaction failures in two provisions. Section 7.5.8A of Chapter 7 of the rules places an obligation on market participants to schedule energy across the intertie in accordance with the relevant interchange schedule. The present rules (section 6.6.10A of Chapter 3) provide for a formula-based penalty if it is determined that there are no 'bona fide and legitimate reasons' for the transaction failing. Section 7.5.8B states that bona fide and legitimate reasons "…include failures caused by actions and circumstances beyond the control of the market participant…" or due to errors or actions by the IESO or external system operator.

Intertie transaction failures affect both Ontario system reliability and market performance. While both are considered important, reliability is identified within the MACD report as the primary goal driving enforcement in this instance. This is consistent with the initiatives recently announced by the IESO designed to improve reliability in preparation for the summer of 2006.

Discussion

It is proposed to no longer treat transaction failures as a compliance matter, except where there appears to be egregious behaviour. Rather, as part of the settlement process, it is proposed that a market participant would compensate the market for transaction failures that are deemed to be under the market participant's control.

As per the above mentioned MACD report: "The attractiveness of the settlement proposal is that it would remove the stigma associated with the allegation and verdict of market rule breaches and the related administrative burden on market participants and MACD in reviewing and remedying alleged breaches." "Market participants would have an incentive to ensure that they navigate the neighbouring markets successfully by virtue of a settlement charge for their failed transactions deemed within their control."

With the settlement charge acting as a deterrent, the incidence of intertie transaction failures is expected to decline under this revised approach for the treatment of transaction failures.

To enable this proposal, market rule amendments are required to:

- the compliance provisions of Chapter 3, as set out below under this MR-00308-R00;
- the provisions relating to compliance with dispatch instructions in Chapter 7 (see MR-00308-R01);
- section 4.18 of Chapter 8 to allow for the return to the transmission rights clearing account of payments that were inappropriately paid to a market participant (see MR-00308-R02); and
- the settlement provisions of Chapter 9 (see MR-00308-R03 and R04).

PART 3 – EXPLANATION FOR PROPOSED AMENDMENT

Section 6.6.10A of Chapter 3 is amended to allow the IESO to respond to failed transactions by taking compliance actions, which may include both imposing a financial penalty or assessing an adjustment to a settlement amount (such as transmission rights payments, congestion management settlement credits or other settlement amounts) that were inappropriately gained or avoided by a market participant. This latter compliance provision to adjust settlement amounts would cover circumstances of egregious behaviour where payment recovery is appropriate and is presently made through the existing formula based penalty. These actions may be taken in addition to levying the new import or export failure charge that has been added to the settlement process as provided in the amended section 7.5.8B of Chapter 7 (see MR-00308-R01).

Sections 6.6.10B and 6.6.10C are deleted. Under the former section 6.6.10 provision market participants could apply to the officers of the IESO for a review of the formulaic penalty amount. With the removal of this penalty, this is no longer required. Under the amended rules market participants would be able to appeal any compliance actions including the penalty and the settlement amount adjustments under the general dispute resolution mechanisms of section 2 of Chapter 3. See section 2.2.1.1 of Chapter 3.

Section 6.6.10C is no longer needed as it refers to the determination of one of the components within the penalty formula that is proposed for deletion.

Appendix 3.1 – Application of Enforcement Actions, which provides a summary of incidence of non-compliance and corresponding enforcement actions, is amended to remove the formula based compliance penalty as an enforcement action.

PART 4 – PROPOSED AMENDMENT

6.6 Non-compliance Letters and Financial Penalties

6.6.1 This section 6.6 sets forth the manner in which the ~~*IMO*~~*IESO* will pursuant to section 6.2.7 issue non-compliance letters and fix financial penalties to be imposed on *market participants* for breaches of the *market rules*.

6.6.2 Where the ~~*IMO*~~*IESO* has determined that it is appropriate to issue a letter of non-compliance under 6.6.5 or impose a financial penalty under section 6.6.6 upon a *market participant*, the ~~*IMO*~~*IESO* shall:

6.6.2.1 determine the level of non-compliance by the *market participant* in accordance with section 6.6.3;

6.6.2.2 determine the rate of recurrence of non-compliance by the *market participant* in accordance with section 6.6.4;

6.6.2.3 based on the determinations made in accordance with sections 6.6.2.1 and 6.6.2.2, determine whether to issue a non-compliance letter or impose a financial penalty; and

6.6.2.4 where a determination is made to impose a financial penalty, fix the amount of the penalty in accordance with section 6.6.6.

6.6.3 The ~~*IMO*~~*IESO* shall determine the level of non-compliance referred to in section 6.6.2.1 as follows:

6.6.3.1 Level "L1" shall be determined where the *market participant* has complied in part, but not in whole, with all the requirements of a *market rule* and where the *market participan*t has, on its own initiative, informed the ~~*IMO*~~*IESO* on a timely basis of the non-compliance, the reasons for non-compliance and the manner in and the time within which such non-compliance will be remedied;

6.6.3.2 Level "L2" shall be determined where the *market participant* has failed to comply with all of the requirements of a *market rule* and where the *market participant* has, of its own initiative, informed the ~~*IMO*~~*IESO* on a timely basis of the non-compliance, the reasons for non-compliance and the manner in which and the time within which such non-compliance will be remedied;

6.6.3.3 Level "L3" shall be determined where the *market participant* has failed to comply, in whole or in part, with all of the requirements of a *market rule* and has failed to inform the ~~*IMO*~~*IESO* of the non-compliance on its own initiative and on a timely basis but, at the ~~*IMO*~~*IESO's* request and within the time specified in the request, informs the ~~*IMO*~~*IESO* of the reasons for non-compliance and the manner in which and the time within which such non-compliance will be remedied; and

6.6.3.4 Level "L4" shall be determined where the *market participant* has failed to comply, in whole or in part, with all of the requirements of a *market rule*, has failed to inform the ~~*IMO*~~*IESO* of the non-compliance on its own initiative and on a timely basis and has failed to respond to the ~~*IMO*~~*IESO's* request, within the time specified in the request, for a statement of the reasons for such non-compliance and of the manner in which and the time within which such non-compliance will be remedied.

6.6.4 The ~~*IMO*~~*IESO* shall determine the rate of recurrence of non-compliance referred to in section 6.6.2.2 based on the frequency and duration with which the *market participant* has been found by the ~~*IMO*~~*IESO* to be in breach of the *market rules*.

6.6.5 Where the ~~*IMO*~~*IESO* has determined, based on the determinations made under section 6.6.2 and the provisions of the chart set forth in section 6.6.6, that the

applicable sanction is the issuance of a letter of non-compliance, the ~~IMO~~IESO shall issue a letter of non-compliance to the *market participant.*

6.6.6 Where the ~~IMO~~IESO has determined, based on the determinations made under section 6.6.2, that the applicable sanction is the imposition of a financial penalty, the ~~IMO~~IESO shall, subject to section 6.6.13, impose on the *market participant* in accordance with section 6.6.7 a financial penalty within the ranges described in the following table:

Level of Non-Compliance	Range of Sanctions
L1	Non-compliance letter or up to $2,000.00
L2	Non-compliance letter or up to $4,000.00
L3	Non-compliance letter or up to $6,000.00
L4	$1,000.00 to $10,000.00

6.6.7 In fixing the amount of the financial penalty within the ranges described in the table set forth in section 6.6.6, the ~~IMO~~IESO shall have regard to:

6.6.7.1 the circumstances in which the breach occurred;

6.6.7.2 the severity of the breach;

6.6.7.3 the extent to which the breach was inadvertent, negligent, deliberate or otherwise;

6.6.7.4 the length of time the breach remained unresolved;

6.6.7.5 the actions of the *market participant* on becoming aware of the breach;

6.6.7.6 whether the *market participant* disclosed the matter to the ~~IMO~~IESO on its own or whether it was prompted to do so;

6.6.7.7 any benefit that the *market participant* obtained or expected to obtain as a result of the breach;

6.6.7.8 any previous breach by the *market participant* of the *market rules* or of the conditions of its *licence*;

6.6.7.9 the impact of the breach on other *market participants*;

6.6.7.10 the impact of the breach on the ~~IMO~~IESO-*administered markets* as a whole;

6.6.7.11 any sanctions that may be imposed on the ~~IMO~~IESO by a *standards authority* as a result of the breach; and

6.6.7.12 such other matters as the ~~IMO~~IESO considers appropriate.

6.6.8 Where Appendix 3.1 provides for the imposition of a formula-based penalty in respect of the breach of a *market rule*, the ~~IMO~~IESO may issue a letter of non-compliance pursuant to sections 6.6.2 and 6.6.5 or impose a financial penalty upon the *market participant*, the amount of which shall be determined by the application of the following formula:

P = D x T x C

Where:

P = the amount of the financial penalty, in dollars

D = the deviation from the applicable obligation in the *market rules*, expressed in terms of MW, MVAR, kV, power factor or other determinant, as specified in Appendix 3.1 in respect of the particular *market rule*

T = the duration of the breach, expressed in hours or fractions of hours

C = the amount determined in accordance with section 6.6.9 in respect of the particular *market rule*

6.6.9 The amount C referred to in section 6.6.8 shall be determined, in respect of the breach of a particular *market rule*, by multiplying the *market price* prevailing at the time of the breach by an amount determined by the ~~IMO~~IESO having regard to the criteria set forth in section 6.6.7 and to the factors noted in sections 6.6.13.1 to 6.6.13.4, where applicable.

6.6.10 Where Appendix 3.1 specifies more than one sanction in respect of the breach of a particular *market rule*, the ~~IMO~~ IESO may impose all of the sanctions so specified on the *market participant* provided that no financial penalty may be imposed in respect of a breach for which the ~~IMO~~IESO has issued a letter of non-compliance pursuant to section 6.6.5. Nothing in this section 6.6.10 shall prevent the ~~IMO~~IESO from imposing a financial penalty for failure by a market participant to remedy a breach in respect of which a letter of non-compliance has been issued or if there is any repetition or continuation of such breach.

6.6.10A ~~Where Appendix 3.1 provides for the imposition of a formula based penalty i~~In respect of a breach of section 7.5.8A of Chapter 7, the ~~IMO~~IESO may~~:, in addition to the other actions set out in section 7.5.8B of Chapter 7,~~

6.6.10A.1 issue a letter of non-compliance or impose a financial penalty upon the *market participant* pursuant to sections 6.6.2, 6.6.5 and 6.6; and

6.6.10A.2 adjust *settlement amounts* paid or payable to a *registered market participant* such as *transmission rights* payments, congestion management *settlement* credits or other *settlement amounts* that the

registered market participant received or avoided due to an act or omission or a course of conduct of either the *registered market participant* alone or the *registered market participant* by agreement or arrangement with one or more other *market participants* that led to the breach of section 7.5.8A of Chapter 7.

~~.5 or, subject to section 6.6.10B, impose a financial penalty upon the *market participant*., the amount of which shall be determined by the application of the following formula:~~

~~P = (D x T x R)*A~~

~~Where:~~

~~P, D and T are defined by section 6.6.8~~

~~R = in the case of a failed *energy interchange schedule,* the greater of the $EMP_h^{m,t}$ or absolute value ($EMP_h^{m,t}$ – *offer/bid* price)~~

~~prevailing at the time of the breach where m = a *primary RWM* (in Ontario)~~

~~R = in the case of a failed *operating reserve interchange schedule,* the greater of the $PROR_{r,h}^{m,t}$ or absolute value ($PROR_{r,h}^{m,t}$ – *offer/bid* price)~~

~~prevailing at the time of the breach where m = a *delivery point* in Ontario and where r = the applicable *class* of *operating reserve*~~

~~A = numeric multiplier determined by the officers of the *IMO*~~*IESO* ~~after consideration of guidelines for that purpose published in the applicable *market manual.*~~

~~6.6.10B The *market participant* may apply to the officers of the *IMO*~~*IESO* ~~in accordance with the applicable *market manual* for a review of the penalty amount resulting from the formula (DxTxR), which amount may be confirmed or changed by the officers.~~

~~6.6.10C The amount A referred to in section 6.6.10A shall, in accordance with the applicable *market manual*, be determined by the officers of the *IMO*~~*IESO* ~~upon the recommendation of the Director, Market Assessment and Compliance Division. In determining that multiplier, the officers shall consider written submissions from the *market participant* made in accordance with the applicable *market manual*, and shall consider the guidelines set out in that manual.~~

6.6.11 Nothing in this section 6.6 shall preclude the ~~*IMO*~~*IESO* from making an order under one or more of sections 6.2.7.1, 6.2.7.2, 6.2.7.3 or 6.2.7.6 in respect of a breach of *the market rules* with respect to which a sanction has been imposed pursuant to this section 6.6.

6.6.12 [Intentionally left blank]

6.6.12.1 [Intentionally left blank]

6.6.12.2 [Intentionally left blank]

6.6.13 The ~~IMO~~IESO may impose on a *market participant* a financial penalty in excess of the amount otherwise provided for in section 6.6.6 where:

6.6.13.1 the *market participant* has breached a market rule while a declaration that the ~~IMO~~IESO-*controlled grid* is in an emergency operating state or a high-risk operating state was in effect;

6.6.13.2 the *market participant* breached a *market rule* while a declaration that *market operations* have been suspended was in effect;

6.6.13.3 the ~~IMO~~IESO *Board* determines that the impact of the *market participant*'s breach on the ~~IMO~~IESO-*administered markets* is particularly severe; or

6.6.13.4 the rate of recurrence of non-compliance by the *market participant* with the *market rules* is of such frequency or duration as to warrant the imposition of a higher financial penalty.

6.6.14 No additional financial penalty may be imposed in respect of a breach of the *market rules* for which a financial penalty has already been imposed pursuant to this section 6.6 provided that nothing in this section 6.6.14 shall prevent the ~~IMO~~IESO from imposing a financial penalty for failure by a *market participant* to remedy a breach in respect of which a financial penalty has been imposed or if there is any repetition or continuation of such breach.

.....

Appendix 3.1 – Application of Enforcement Actions

Non-compliance	Enforcement Action
Chapter 4, section 3.1.2	Sanctions as per section 6.6.5 or 6.6.6 Disconnection order as per section 6.5
Chapter 4, section 3.3.1.6	Sanctions as per section 6.6.5 or 6.6.6 Disconnection order as per section 6.5
Chapter 4, section 6.1.6	Sanctions as per section 6.6.5 or 6.6.6 Disconnection order as per section 6.5
Chapter 5, section 3.4.1.1	Formula based penalty as per section 6.6.8 of Chapter 3 where;

	D= load shedding capability required (MW) C= Market Price x amount determined by the ~~IMO~~*IESO* under section 6.6.9
Chapter 5, section 3.4.1.2	Formula based penalty as per section 6.6.8 of Chapter 3 where; D= load shedding capability required including its restoration (MW) C= Market Price x amount determined by the ~~IMO~~*IESO* under section 6.6.9
Chapter 5, section 3.5.1.1	Formula based penalty as per section 6.6.8 of Chapter 3 where; D= load shedding capability required including its restoration (MW) C= Market Price x amount determined by the ~~IMO~~*IESO* under section 6.6.9
Chapter 5, section 3.6.1.1	Formula based penalty as per section 6.6.8 where; D= nominal generation capacity (MCR) barring declared limitations (MW) C= Market Price x amount determined by the ~~IMO~~*IESO* under section 6.6.9
Chapter 5, section 3.7.1.1	Formula based penalty as per section 6.6.8 where; D= load shedding capability required (MW) C= Market Price x amount determined by the ~~IMO~~*IESO* under section 6.6.9
Chapter 5, section 6.3.10	Formula based penalty as per section 6.6.8 where: D = the amount by which the offer made is less than the MW which the generator had agreed would be offered in support of the planned outage or the extension to or rescheduling of an outage. C = market price x amount to be determined by the ~~IMO~~*IESO* under section 6.6.9
App 5.1, section 1.2.1	Formula based penalty as per section 6.6.8 where; D= resource deviation (MW) C= Market Price x amount determined by the ~~IMO~~*IESO* under section 6.6.9.
App 5.1, section 1.2.4	Formula based penalty as per section 6.6.8 where; D= resource deviation (MW) C= Market Price x amount determined by the ~~IMO~~*IESO* under section 6.6.9.
App 5.1, section 1.2.2	Formula based penalty as per section 6.6.8 where; D= ramp rate deviation (MW) C= Market Price x amount determined by the ~~IMO~~*IESO* under section 6.6.9.
App 5.1, section 1.2.5	Formula based penalty as per section 6.6.8 where; D= ramp rate deviation (MW) C= Market Price x amount determined by the ~~IMO~~*IESO* under section 6.6.9.
App 5.1, section 1.2.3	Formula based penalty as per section 6.6.8 where; D= resource deviation (MW) C= Market Price x amount determined by the ~~IMO~~*IESO* under section 6.6.9.

App 5.1, section 1.2.6	Formula based penalty as per section 6.6.8 where; D= resource deviation (MW) C= Market Price x amount determined by the ~~IMO~~*IESO* under section 6.6.9.
Chapter 5, section 10.3.3	Formula based penalty as per section 6.6.8 where; D= deviation from direction (MW) C= Market Price x amount determined by the ~~IMO~~*IESO* under section 6.6.9
Chapter 5, section 10.3.4	Formula based penalty as per section 6.6.8 where; D= deviation from direction (MW) C= Market Price x amount determined by the ~~IMO~~*IESO* under section 6.6.9
Non-compliance	**Enforcement Action**
Chapter 5, section 10.3.5	Formula based penalty as per section 6.6.8 where; D= deviation from direction (MW) C= *Market Price* x amount determined by the ~~*IMO*~~ *IESO* under section 6.6.9
~~Chapter 7, section 7.5.8A, 7.5.8B~~	~~Formula based penalty as per section 6.6.10A~~

PART 5 – IESO BOARD DECISION RATIONALE

Insert Text Here

Market Rule Amendment Proposal

PART 1 – MARKET RULE INFORMATION

Identification No.:	MR-00308-R01			
Subject:	Intertie Transactions			
Title:	Settlement Charges for Real-Time Intertie Transaction Failures			
Nature of Proposal:	☒ Alteration	☐ Deletion	☐ Addition	
Chapter:	7	Appendix:		
Sections:	7.5.8B			
Sub-sections proposed for amending:				

PART 2 – PROPOSAL HISTORY

Version	Reason for Issuing	Version Date
Approved Amendment Publication Date:		
Approved Amendment Effective Date:		

PART 3 – EXPLANATION FOR PROPOSED AMENDMENT

Provide a brief description of the following:

- The reason for the proposed amendment and the impact on the *IESO-administered markets* if the amendment is not made.
- Alternative solutions considered.
- The proposed amendment, how the amendment addresses the above reason and impact of the proposed amendment on the *IESO-administered markets*.

Summary

See MR-00308-R00.

Background

See MR-00308-R00.

Discussion

Section 7.5.8B, Compliance with Dispatch Instructions is amended to allow for the application of the new settlement provisions of section 3.8C of Chapter 9 (see MR-00308-R03), when boundary entities, other than for "bona fide and legitimate reasons", fail to schedule energy with the appropriate scheduling entities.

PART 4 – PROPOSED AMENDMENT

7.5.8A A *registered market participant* associated with a *registered facility* that is a *boundary entity* shall, other than for the bona fide and legitimate reasons referred to in section 7.5.8B, schedule *energy* and *operating reserve*, in accordance with section 6.1.3, with the appropriate scheduling entity, or scheduling entities as the case may be.

7.5.8B The *IESO~~IMO~~* may~~shall~~ take actions pursuant to section 6.6.10A of Chapter 3 and shall assess a real-time import or export failure charge as determined in section 3.8C of Chapter 9 where a *registered market participant* associated with a *registered facility* that is a *boundary entity* fails to schedule *energy* or *operating reserve*, in accordance with section 6.1.3 of Chapter 7, with the appropriate scheduling entity, or scheduling entities as the case may be, according to the applicable *interchange schedule*, other than for bona fide and legitimate reasons as determined by the *IESO~~IMO~~*. Bona fide and legitimate reasons shall include failures caused by actions and circumstances beyond the control of the *market participant* or due to *IESO~~IMO~~* or external scheduling entity error or action, including those reasons specified in the applicable *market manual*.

PART 5 – IESO BOARD DECISION RATIONALE

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PART 5 – IESO BOARD DECISION RATIONALE

Market Rule Amendment Proposal

PART 1 – MARKET RULE INFORMATION

Identification No.:	MR-00308-R02			
Subject:	Intertie Transactions			
Title:	Settlement Charges for Intertie Transaction Failures			
Nature of Proposal:	☒ Alteration	☐ Deletion	☐ Addition	
Chapter:	8	Appendix:		
Sections:	4.18			
Sub-sections proposed for amending:	4.18.1			

PART 2 – PROPOSAL HISTORY

Version	Reason for Issuing	Version Date
Approved Amendment Publication Date:		
Approved Amendment Effective Date:		

PART 3 – EXPLANATION FOR PROPOSED AMENDMENT

Provide a brief description of the following:

- The reason for the proposed amendment and the impact on the *IESO-administered markets* if the amendment is not made.
- Alternative solutions considered.
- The proposed amendment, how the amendment addresses the above reason and impact of the proposed amendment on the *IESO-administered markets*.

Summary

See MR-00308-R00.

Background

See MR-00308-R00.

Discussion

Section 4.18.1 of Chapter 8 is amended to recognize the potential for the return of any transmission rights payments to the transmission rights clearing account. This amendment is consequential to the amendment of section 6.6.10A.2 of Chapter 3. See MR-00308-R00.

PART 4 – PROPOSED AMENDMENT

4.18 TR Clearing Account

4.18.1 The ~~*IMO*~~*IESO* shall establish and maintain a *TR clearing account* and shall:

4.18.1.1 credit to the *TR clearing account*, in respect of each *settlement hour*, the net congestion rents calculated in accordance with section 3.6.2 of Chapter 9;

4.18.1.1A credit to the *TR clearing account* the amounts referred to in sections 4.20.1A and 4.20.1B;

4.18.1.2 subject to section 4.19.7, credit to the *TR clearing account* the net revenues received from the sale of *transmission rights* in a *TR auction* in accordance with section 4.19.4;

4.18.1.3 debit from the *TR clearing account* any amounts required to be paid to *TR holders* pursuant to section 4.4.1;

4.18.1.4 debit from the *TR clearing account* any amounts required to be paid to successful *TR offerors* pursuant to section 4.19.6; ~~and~~

4.18.1.5 debit from the *TR clearing account* any amounts authorized to be debited and used to offset *transmission services charges* in accordance with section 4.18.2; and.

4.18.1.6 credit to the *TR clearing account* any transmission rights settlement credits adjusted under section 6.6.10A.2 of Chapter 3.

4.18.2 Subject to section 4.18.3, the ~~*IMO*~~*IESO Board* may, at such times at it determines appropriate, authorize the debit of funds from the *TR clearing account* for the purpose of using those funds to offset the *transmission services charges* referred to in section 3.6.3 of Chapter 9.

4.18.3 The ~~*IMO*~~*IESO Board* shall establish a reserve threshold for the *TR clearing account.*

PART 5 – IESO BOARD DECISION RATIONALE

Insert Text Here

Market Rule Amendment Proposal

PART 1 – MARKET RULE INFORMATION

Identification No.:	MR-00308-R03			
Subject:	Intertie Transactions			
Title:	Settlement Charges for Intertie Transaction Failures			
Nature of Proposal:	☒ Alteration	☐ Deletion	☐ Addition	
Chapter:	9	Appendix:		
Sections:	3.1 and 3.8C			
Sub-sections proposed for amending:				

PART 2 – PROPOSAL HISTORY

Version	Reason for Issuing	Version Date
Approved Amendment Publication Date:		
Approved Amendment Effective Date:		

PART 3 – EXPLANATION FOR PROPOSED AMENDMENT

Provide a brief description of the following:

- The reason for the proposed amendment and the impact on the *IESO-administered markets* if the amendment is not made.
- Alternative solutions considered.
- The proposed amendment, how the amendment addresses the above reason and impact of the proposed amendment on the *IESO-administered markets*.

Summary

See MR-00308-R00.

Background

See MR-00308-R00.

Discussion

The following changes are required to the settlement provisions of Chapter 9.

- An amended section 3.1, Hourly Settlement Variables and Data;
- A new section 3.8C, Real-Time Import and Real-Time Export Failure Charges;
- An amended section 3.9, Hourly Uplift Settlement Amounts (see MR-00308-R04); and
- An amended section 4.8, Additional Non-Hourly Settlement Amounts (see MR-00308-R04).

Section 3.1, Hourly Settlement Variables and Data is amended to obligate the IESO to provide the settlement data needed to ensure that the settlement process has the necessary data to determine the hourly settlement amounts using the formulations provided in the new section 3.8C, Real-Time Import and Real-Time Export Failure Charges. This data includes pre-dispatch energy amounts (section 3.1.2C), exceptions from the transaction failure charges in those instances where there are "bona fide and legitimate reasons" for the failure (sections 3.1.2D.1 and 3.1.2D.2) and a price bias adjustment factor that is part of the transaction failure charge formulation as explained below.

Section 3.8C, Real-Time Import and Real-Time Export Failure Charges provides the following separate formulations for imports and exports. Under these formulas market participants would compensate the market when intertie transactions deviate from the hour ahead pre-dispatch schedule. The intertie failure charge has been developed so that the charge is limited in the case of imports to the Ontario real-time energy market price and in the case of exports to the pre-dispatch Ontario price. The import failure charge is the mirror image of the export failure charge.

In the case of an import:

$$RT_IFC_{k,h} = \sum^{I,T} (-1) \times MIN\left[MAX\left[0, (EMP_h^{m,t} + PB_IM_h^{t} - PD_EMP_h^{m,t}) \times RT_ISD_{k,h}^{i,t}\right], MAX(0, EMP_h^{m,t}) \times RT_ISD_{k,h}^{i,t}\right]$$

This summation formula is described more fully within the rule amendment, but basically it states that the real-time import failure charge (RT_IFC) equals the lesser (MIN) of two terms:

1. The first term is the maximum (MAX) of zero and the product of (EMP + PB_IM – PD_EMP) and

PART 3 – EXPLANATION FOR PROPOSED AMENDMENT

RT_ISD that calculates a charge based on:

the sum of the real-time energy market price (EMP) and a price bias adjustment factor for imports (PB_IM), less the pre-dispatch energy market price in Ontario (PD_EMP), all multiplied by the real time import scheduling deviation (RT_ISD).

The price bias adjustment factor accounts for influences that cause bias between real-time and pre-dispatch prices. This price bias may be adjusted periodically by the IESO, and must be published in advance of its application to the settlement charge. See amendment sections 3.1.2D.4, 3.8C.7 and 3.8C.8.

2. The second term is the product of:

   the maximum (MAX) of zero and the real-time energy market price (EMP), and the real-time import scheduling deviation (RT_ISD).

   This second term caps the charge for the deviation from schedule to the real-time energy market price.

The following formula for the real-time export failure charge applies to exports and is the mirror image to the above import charge.

$$RT_EFC_{k,h} = \sum^{I,T}(-1)\times MIN\left[MAX\left[0,(PD_EMP_h^{m,t} - EMP_h^{m,t} - PB_EX_h^{t})\times RT_ESD_{k,h}^{i,t}\right], MAX(0,PD_EMP_h^{i,t})\times RT_ESD_{k,h}^{i,t}\right]$$

In the case of the real-time export failure charge, the second term utilizes the pre-dispatch price in Ontario as the cap price.

For import transactions that are subject to both the day ahead and real-time import failure charges, the greater of the two charges apply. See section 3.8C.6.

PART 4 – PROPOSED AMENDMENT

3.1 Hourly Settlement Variables and Data

……

3.1.2C The *IESO* shall determine from the *pre-dispatch schedule* and the *pre-dispatch* projected *market schedule,* and provide directly to the *settlement process* the following *pre-dispatch prices* and quantities:

$PD_DQSI_{k,h}^{i,t}$ = *pre- dispatch* constrained quantity scheduled for injection by *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h'.

$PD_DQSW_{k,h}^{i,t}$ = *pre- dispatch* constrained quantity scheduled for withdrawal by *market participant* 'k' at *intertie metering point* 'i' during

metering interval 't' of *settlement hour* 'h'.

$PD_EMP_h^{m,t}$ = *pre-dispatch* projected *energy market price* applicable to all *delivery points* 'm' in the Ontario zone in *metering interval* 't' of *settlement hour* 'h'

In instances where this variable is provided to the *settlement process* on an hourly basis as determined in section 3.9, it shall be deemed to apply uniformly to all *metering intervals* 't' in *settlement hour* 'h'.

3.1.2D The *IESO* shall provide directly to the *settlement process:*

3.1.2D.1 exceptions from the real-time import failure charge set out in section 3.8C.2 for any applicable import transactions scheduled in the *pre-dispatch schedule* where such exceptions have been determined in accordance with chapter 7, section 7.5.8B;

3.1.2D.2 exceptions from the real-time export failure charge set out in section 3.8C.4 for any applicable export transactions scheduled in the *pre-dispatch schedule* where such exceptions have been determined in accordance with chapter 7, section 7.5.8B;

3.1.2D.3 the adjustment of amounts provided for in section 6.6.10A.2 of Chapter 3; and

3.1.2D.4 any applicable price bias adjustment factors, as described in section 3.8C.7, utilised in the calculation of the:

a. real-time import failure charge; or

b. real-time export failure charge

that are in effect as of the *settlement hour* in which such *settlement amounts* are calculated by the *IESO*.

.....

3.8C Real-Time Import and Real-Time Export Failure Charges

3.8C.1 The real-time import failure charge and the real-time export failure charges referred to in section 7.5.8B of Chapter 7 are *settlement amounts* that shall be determined in sections 3.8C.2 and 3.8C.3 and in sections 3.8C.4 and 3.8C.5, respectively.

Real-time Import Failure Charge

3.8C.2 The *IESO* shall assess a *market participant* with a real-time import failure charge for any quantity of *energy* scheduled for injection at an *intertie metering point* in the constrained *pre-dispatch schedule* where:

3.8C.2.1 the *market participant* fails either in whole or in part to schedule a *dispatch* quantity for injection in the constrained *real-time schedule* in the corresponding *metering interval* of the corresponding *settlement hour* at the same *intertie metering point;* and,

3.8C.2.2 the *IESO* has not determined, nor has the *market participant* demonstrated to the satisfaction of the *IESO,* that the failure was due to bona fide and legitimate reasons as described in chapter 7, section 7.5.8B.

3.8C.3 For all import transactions scheduled in the constrained *pre-dispatch schedule* and meeting the criteria set out in section 3.8C.2, the real-time import failure charge shall be formulated as follows:

Let $RT_ISD_{k,h}^{i,t}$ be the real-time import scheduling deviation quantity calculated for *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h' as determined by the formula:

Real-time Import Scheduling Deviation Quantity = MAX (*pre-dispatch* import transaction quantity – real-time import transaction quantity, 0)

$$RT_ISD_{k,h}^{i,t} = MAX\left(PD_DQSI_{k,h}^{i,t} - DQSI_{k,h}^{i,t}, 0\right)$$

such that the real-time import failure charge for *market participant* 'k' during *settlement hour* 'h' for all *intertie metering points*'i' may be formulated with the above components as follows:

$RT_IFC_{k,h}$ = For all *intertie metering points*:

-1 x [MAXIMUM of:

[[The difference between: the real-time *energy market price* in the Ontario zone adjusted by the prevailing price bias adjustment factor for imports in effect for the *settlement hour* minus the *pre-dispatch* projected *energy market price* in the Ontario zone

times :

real-time import scheduling deviation quantity.]

or zero,]

subject to: a maximum value of the real-time import

scheduling deviation quantity times the maximum of the real-time *energy market price* in the Ontario zone or zero]

$$RT_IFC_{k,h} = \sum^{I,T}(-1)\times MIN\left[MAX\left[0,(EMP_h^{m,t} + PB_IM_h^{t} - PD_EMP_h^{m,t})\times RT_ISD_{k,h}^{i,t}\right], MAX(0,EMP_h^{m,t})\times RT_ISD_{k,h}^{i,t}\right]$$

where:

$PD_EMP_h^{m,t}$ is the pre-dispatch projected *energy market price* applicable to all *delivery points* 'm' in the Ontario zone during *metering interval* 't' of *settlement hour* 'h'

$EMP_h^{m,t}$ is the real-time 5-minute *energy market price* applicable to all *delivery points* 'm' in the Ontario zone during *metering interval* 't' of *settlement hour* 'h'

$PB_IM_h^{t}$ is the price bias adjustment factor for import transactions in effect during *metering interval* 't' of *settlement hour* 'h'

'I' is the set of all *intertie metering points* 'i'

'T' is the set of all *metering intervals* in *settlement hour* 'h'

Real-time Export Failure Charge

3.8C.4 The *IESO* shall assess a *market participant* with a real-time export failure charge for any quantity of *energy* scheduled for withdrawal at an *intertie metering point* in the constrained *pre-dispatch schedule* where:

3.8C.4.1 the *market participant* fails either in whole or in part to schedule a *dispatch* quantity for withdrawal in the constrained *real-time schedule* in the corresponding *metering interval* of the corresponding *settlement hour* at the same *intertie metering point;* and,

3.8C.4.2 the *IESO* has not determined, nor has the *market participant* demonstrated to the satisfaction of the *IESO,* that the failure was due to bona fide and legitimate reasons described in chapter 7, section 7.5.8B.

3.8C.5 For all export transactions scheduled in the constrained *pre-dispatch schedule* and meeting the criteria set out in section 3.8C.4, the real-time export failure charge shall be formulated as follows:

Let $RT_ESD_{k,h}^{i,t}$ be the real-time export scheduling deviation quantity calculated for *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h' as determined by the formula:

Real-time Export Scheduling Deviation Quantity = MAX (*pre-dispatch* export transaction quantity – real-time export transaction quantity, 0)

$RT_ESD_{k,h}^{i,t}$ = MAX ($PD_DQSW_{k,h}^{i,t}$ - $DQSW_{k,h}^{i,t}$, 0)

such that the real-time export failure charge for *market participant* 'k' during *settlement hour* 'h' for all *intertie metering points* 'i' may be formulated with the above components as follows:

$RT_EFC_{k,h}$ = For all *intertie metering points*:

-1 x [MAXIMUM of:

[[The difference between the *pre-dispatch* projected *energy market price* in the Ontario zone minus the real-time *energy market price* in the Ontario zone adjusted by the prevailing price bias adjustment factor for exports in effect for the *settlement hour]*

times :

real-time export scheduling deviation quantity.]

or zero,]

subject to: a maximum value of the:

real-time export scheduling deviation quantity times the maximum of the pre-dispatch *energy market price* in the Ontario zone or zero]

$$RT_EFC_{k,h} = \sum^{I,T}(-1)\times MIN\left[MAX\left[0,(PD_EMP_h^{m,t} - EMP_h^{m,t} - PB_EX_h^{t})\times RT_ESD_{k,h}^{i,t}\right], MAX(0,PD_EMP_h^{m,t})\times RT_ESD_{k,h}^{i,t}\right]$$

where:

$PD_EMP_h^{m,t}$ is the *pre-dispatch* projected *energy market price* applicable to all *delivery points* 'm' in the Ontario zone during *metering interval* 't' of *settlement hour* 'h'

$EMP_h^{m,t}$ is the real-time 5-minute *energy market price* applicable to all *delivery points* 'm' in the Ontario zone during *metering interval* 't' of *settlement hour* 'h'

$PB_EX_h^t$ is the price bias adjustment factor for export transactions in effect during *metering interval* 't' of *settlement hour* 'h'

'I' is the set of all *intertie metering points* 'i'

'T' is the set of all *metering intervals* in *settlement hour* 'h'

3.8C.6 Where any import transaction scheduled in the *pre-dispatch schedule of record* and subsequently scheduled at the same *intertie metering point* in the *real-time market* is subject to both the day ahead import failure charge of section 3.8B and the real-time import failure charge of section 3.8C, the *market participant* shall be assessed with the greater of these charges but not both.

3.8C.7 The *IESO* shall determine, in accordance with the applicable *market manual*, any applicable price bias adjustment factors to be used in the calculation of the real-time import failure charge and the real-time export failure charge. The price bias adjustment factor shall compensate for systematic differences between the pre-dispatch and real-time price.

3.8C.8 The *IESO* shall *publish* all applicable price bias adjustment factors in advance of the *settlement hours* to which such factors apply.

PART 5 – IESO BOARD DECISION RATIONALE

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Market Rule Amendment Proposal

PART 1 – MARKET RULE INFORMATION

Identification No.:	MR-00308-R04			
Subject:	Intertie Transactions			
Title:	Settlement Charges for Intertie Transaction Failures			
Nature of Proposal:	☒ Alteration	☐ Deletion	☐ Addition	
Chapter:	Chapter 9	Appendix:		
Sections:	3.9 and 4.8			
Sub-sections proposed for amending:	3.9.1, 3.9.5 and 4.8.2			

PART 2 – PROPOSAL HISTORY

Version	Reason for Issuing	Version Date
Approved Amendment Publication Date:		
Approved Amendment Effective Date:		

PART 3 – EXPLANATION FOR PROPOSED AMENDMENT

Provide a brief description of the following:

- The reason for the proposed amendment and the impact on the *IESO-administered markets* if the amendment is not made.
- Alternative solutions considered.
- The proposed amendment, how the amendment addresses the above reason and impact of the proposed amendment on the *IESO-administered markets*.

Summary

See MR-00308-R00.

Background

See MR-00308-R00.

Discussion

Section 3.9, Hourly Uplift Settlement Amounts is amended to include the transaction failure settlement amounts in the hourly uplift settlement amount. The uplift is to be distributed monthly on an interim basis until such time as the IESO has the software capability to distribute the payments hourly. See sections 3.9.4 and 3.9.5.

Until the IESO has the software capability to distribute the payments hourly, **Section 4.8, Additional Non-Hourly Settlement Amounts** is amended to include the transaction failure settlement amounts in monthly distributions.

Revenue that is recovered under the amended section 6.10A.3 of Chapter 3 would also be included in the monthly distribution amounts of section 4.8.

PART 4 – PROPOSED AMENDMENT

3.9 Hourly Uplift Settlement Amounts

3.9.1 The hourly *settlement amounts* defined by the preceding provisions of this section 3 will result in an hourly *settlement* deficit that shall be recovered from *market participants* as a whole through the *hourly uplift*. The total *hourly uplift settlement amount* for *settlement hour* h ("$HUSA_h$") shall be determined according to the following equation:

$HUSA_h$ = $\Sigma_k(NEMSC_{k,h}+ORSC_{k,h}+ CAPRSC_{k,h} +CMSC_{k,h}+TRSC_{k,h}+IOG_{k,h} +DA_IOG_{k,h}) +TCRF_h - \Sigma_k (CRSSD_{k,h} + \Sigma_r ORSSD_{k,r,h} + DA_IFC_{k,h}+ RT_IFC_{k,h}+ RT_EFC_{k,h})$

over all k *market participants*

$NEMSC_{k,h}$ = net *energy market settlement* credit for *market participant k* in *settlement hour h*

$ORSC_{k,h}$ = *operating reserve market settlement* credit for *market participant k* in *settlement hour h*

$CAPRSC_{k,h}$ = *capacity reserve market settlement* credit for *market participant k* in *settlement hour h*

$CMSC_{k,h}$ = congestion management *settlement* credit for *market participant k* in *settlement hour* h

$TRSC_{k,h}$ = *transmission rights settlement* credit for *market participant k* in *settlement hour h*

$IOG_{k,h}$ = *intertie offer* guarantee *settlement* credit for the *market participant* k in *settlement hour* h

$DA_IOG_{k,h}$ = day-ahead *intertie offer* guarantee *settlement* credit for the *market participant* k in *settlement hour* h

$DA_IFC_{k,h}$= day-ahead import failure charge for the *market participant* k in *settlement hour* h

$RT_IFC_{k,h}$ = real-time import failure charge for the *market participant* 'k' in *settlement hour* 'h'

$RT_EFC_{k,h}$= real-time export failure charge for the *market participant* 'k' in *settlement hour* 'h'

$TCRF_h$ = transmission charge reduction fund contribution in *settlement hour* h

$CRSSD_{k,h}$ = *capacity reserve settlement* debit for *operating deviations* for *market participant* k in *settlement hour* h

$ORSSD_{k,r,h}$ = *operating reserve settlement* debit for *operating deviations* for *class 'r' reserve* for *market participant* k in *settlement hour* h

[NTD: the following section 3.9.4 is taken from proposed rule amendment MR-00305-R03. It is included here for information.]

3.9.4 Until such time that the *IESO* has the software capability to include the following *settlement amounts*:

- the day-ahead *intertie offer* guarantee *settlement* ($DA_IOG_{k,h}$)*; or*
- the day-ahead import failure charge ($DA_IFC_{k,h}$),

in the *hourly uplift settlement amount,* the *IESO* shall recover or distribute such *settlement amounts* as non-hourly *settlement amounts* under the provisions of section 4.8.1 or 4.8.2 respectively for an interim period of time commencing with the activation of the day-ahead commitment process.

3.9.5 Until such time that the *IESO* has the software capability to include the following *settlement amounts*:

- the real-time import failure charge ($RT_IFC_{k,h}$); *or*
- the real-time export failure charge ($RT_EFC_{k,h}$),

in the *hourly uplift settlement amount,* the *IESO* shall recover or distribute such *settlement amounts* as non-hourly *settlement amounts* under the provisions of section 4.8.2.

4.8 Additional Non-Hourly Settlement Amounts

4.8.2 The ~~*IMO*~~ *IESO* shall, at the end of each *energy market billing period*, distribute to *market participants*, on a pro-rata basis across all allocated quantities of *energy* withdrawn at all *RWMs* and *intertie metering points* during all *metering intervals* and *settlement hours* within that *energy market billing period*, the following amounts:

……..

4.8.2.9 any proceeds from the real-time import failure charge or the real--time export failure charge that in accordance with section 3.9.5 are not distributed as a component of *hourly uplift*; and

4.8.2.10 any proceeds from the recovery of congestion management *settlement* credits or other *settlement amounts* in accordance with section 6.6.10A.2 of Chapter 3, excluding any payments recovered under section 4.18.1.6 of Chapter 8.

PART 5 – IESO BOARD DECISION RATIONALE

Import/export failures can result in adverse impacts on reliability and market efficiency. This amendment represents a market-based solution to import/export failures and is expected to result in a reduction in the number of failures.

Exhibit “K”

Chapter 1 of the IESO Market Rules issued June 2, 2021

Exhibit “K”

to the Affidavit of Robin Doolittle

Sworn before me on October 29, 2025, in accordance with O. Reg. 431/20, Administering Oath or Declaration Remotely



Commissioner for Taking Affidavits
(or as may be)

October 29, 2025

Keith Edward Hickey, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.

Expires June 24, 2027.

Market Rules

Chapter 1

Introduction And Interpretation Of The Market Rules

Public

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1. Definitions

1.1 Market Rules

1.1.1 The rules set forth in Chapters 1 to 11 are called the Market Rules for the Ontario Electricity Market (the "*market rules*") and constitute the *market rules* made under the authority and for the purposes of the *Electricity Act, 1998*.

1.2 Italicized Expressions

1.2.1 Italicized expressions used in the *market rules* have the meanings ascribed thereto in the definitions set forth in Chapter 11. Words and phrases defined in the *Electricity Act, 1998* have the same meaning when used in the *market rules*.

2. Background and Legislative Authority

2.1 White Paper

2.1.1 In November, 1997, the Government of Ontario issued a White Paper entitled "Direction for Change: Charting a Course for Competitive Electricity and Jobs in Ontario", which set forth the broad framework for electricity sector reform with a view to the establishment of a competitive electricity market in Ontario.

2.2 Market Design Committee

2.2.1 During the course of 1998 and early 1999, the Market Design Committee, a committee created by Order in Council 2156/97 and comprised of representatives of stakeholders and consumers within the electricity industry, in its four quarterly reports made recommendations to the Government of Ontario on the design of the competitive electricity market for Ontario. As part of its responsibilities, the Market Design Committee was tasked with the preparation of initial draft rules governing the Ontario wholesale electricity market for submission to the *Minister*. In late January, 1999, the Market Design Committee submitted a set of draft initial rules to the *Minister*, with such further development of and revisions to the draft initial rules as may be necessary or appropriate being contemplated to be made prior to opening of the competitive markets.

2.3 Legislative Authority

2.3.1 The legislative authority for the *market rules* is contained in the *Electricity Act, 1998*. Specifically, subsection 32(1) of the *Electricity Act, 1998* contemplates that there will be made rules governing the *IESO-controlled grid* and establishing and governing the *IESO-administered markets* related to electricity and *ancillary services*.

3. Market Objective

3.1.1 The objective of the *IESO-administered markets* is to promote an efficient, competitive and reliable market for the wholesale sale and purchase of electricity and *ancillary services* in Ontario.

4. Objectives and Status of Market Rules

4.1 Objectives and Status of Market Rules

4.1.1 The objectives of the *market rules* are to govern the *IESO-controlled grid* and to establish and govern efficient, competitive and reliable markets for the wholesale sale and purchase of electricity and *ancillary services* in Ontario.

4.2 Purposes of Market Rules

4.2.1 Accordingly, the *market rules* include provisions:

4.2.1.1 governing the making, *amendment* and *publication* of the *market rules*;

4.2.1.2 governing the conveying of electricity into, through or out of the *IESO-controlled grid* and the provision of *ancillary services*;

4.2.1.3 governing the terms and conditions pursuant to which persons may be authorized by the *IESO* to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid*;

4.2.1.4 governing the manner in which electricity and *ancillary services* are sold, purchased and *dispatched* in the *IESO-administered markets*;

4.2.1.5 governing standards and procedures to be observed in system *emergencies*;

4.2.1.6 authorizing and governing the giving of directions by the *IESO*;

4.2.1.7 authorizing and governing the making of orders by the *IESO*;

4.2.1.8 providing a mechanism for the resolution of certain disputes arising under the *market rules*;

4.2.1.9 providing mechanisms for monitoring, surveillance and investigation of activities in the *IESO-administered markets* and the conduct of *market participants*; and

4.2.1.10 providing generally for the exercise by the *IESO* of such powers and authority as may be necessary or desirable for the purpose of carrying out its objects in relation to the *IESO-administered markets* and the *IESO-controlled grid*.

4.3 Contractual Force

4.3.1 The *market rules* have the effect of a contract between each *market participant* and the *IESO* by virtue of the execution by the *IESO* and each *market participant* of the *participation agreement* under which each *market participant* and the *IESO* agree to perform and observe the *market rules* so far as they are applicable to each *market participant* and the *IESO* as provided for in the *market rules,* their respective *licences* and *applicable law*.

4.4 [Intentionally left blank – section deleted]

4.4.1 [Intentionally left blank – section deleted]

4.4.2 [Intentionally left blank – section deleted]

4.4.3 [Intentionally left blank – section deleted]

4.4.4 [Intentionally left blank – section deleted]

4.4.4.1 [Intentionally left blank – section deleted]

4.4.4.2 [Intentionally left blank – section deleted]

4.4.5 [Intentionally left blank – section deleted]

4.4.6 [Intentionally left blank – section deleted]

4.4.7 [Intentionally left blank – section deleted]

4.4.7.1 [Intentionally left blank – section deleted]

4.4.7.2 [Intentionally left blank – section deleted]

4.4.8 [Intentionally left blank – section deleted]

4.4.9 [Intentionally left blank – section deleted]

4.4A [Intentionally left blank – section deleted]

4.4A.1 [Intentionally left blank – section deleted]

4.4A.2 [Intentionally left blank – section deleted]

4.4A.2.1 [Intentionally left blank- section deleted]

4.4A.2.2 [Intentionally left blank – section deleted]

a. [Intentionally left blank – section deleted]
b. [Intentionally left blank – section deleted]
c. [Intentionally left blank – section deleted]

4.4A.2.3 [Intentionally left blank – section deleted]

4.4A.3 [Intentionally left blank – section deleted]

4.4A.4 [Intentionally left blank – section deleted]

4.4A.4.1 [Intentionally left blank – section deleted]

4.4A.4.2 [Intentionally left blank – section deleted]

a. [Intentinally left blank – section deleted]
b. [Intentinally left blank – section deleted]
c. [Intentionally left blank – section deleted]

4.4A.4.3 [Intentionally left blank – section deleted]

4.4A.5 [Intentionally left blank – section deleted]

4.4A.6 [Intentionally left blank – section deleted]

4.4A.6.1 [Intentionally left blank – section deleted]

4.4A.6.2 [Intentionally left blank – section deleted]

a. [Intentionally left blank – section deleted]

b. [Intentionally left blank – section deleted]

4.4B Transitional Scheduling Generator

4.4B.1 Participation in the *IESO-administered market* of a *transitional scheduling generator* is temporary and shall expire when its registration is changed pursuant to Chapter 7, section 2.2.23.

4.5 [Intentionally left blank – section deleted]

4.5.1 [Intentionally left blank – section deleted]

4.5.1.1 [Intentionally left blank – section deleted]

4.5.1.2 [Intentionally left blank – section deleted]

4.5.1.3 [Intentionally left blank – section deleted]

4.5.2 [Intentionally left blank – section deleted]

4.5.2.1 [Intentionally left blank – section deleted]

4.5.2.2 [Intentionally left blank – section deleted]

4.5.2.3 [Intentionally left blank – section deleted]

4.5.2.4 [Intentionally left blank – section deleted]

4.5.2.5 [Intentionally left blank – section deleted]

4.5.2.6 [Intentionally left blank – section deleted]

4.5.2.7 [Intentionally left blank – section deleted]

4.5.2.8 [Intentionally left blank – section deleted]

4.5.2.9 [Intentionally left blank – section deleted]

4.5.2.10 [Intentionally left blank – section deleted]

4.5.2.11 [Intentionally left blank – section deleted]

4.5.2.12 [Intentionally left blank – section deleted]

4.5.2.13 [Intentionally left blank – section deleted]

4.5.2.14 [Intentionally left blank – section deleted]

4.5.2.15 [Intentionally left blank – section deleted]

4.5.2.16 [Intentionally left blank – section deleted]

4.5.2.17 [Intentionally left blank – section deleted]

4.5.2.18 [Intentionally left blank – section deleted] [Intentionally left blank – section deleted]

4.5.2.19 [Intentionally left blank – section deleted]

4.5.3 [Intentionally left blank – section deleted]

4.5.3.1 [Intentionally left blank – section deleted]

4.5.3.2 [Intentionally left blank – section deleted]

4.5.4 [Intentionally left blank – section deleted]

4.5.5 [Intentionally left blank – section deleted]

4.5.6 [Intentionally left blank – section deleted]

4.5.6.1 [Intentionally left blank – section deleted]

4.5.6.2 [Intentionally left blank – section deleted]

4.5.6.3 [Intentionally left blank – section deleted]

4.5.6.4 [Intentionally left blank – section deleted]

4.5.6.5 [Intentionally left blank – section deleted]

4.5.7 [Intentionally left blank – section deleted]

4.5.7.1 [Intentionally left blank – section deleted]

4.5.7.2 [Intentionally left blank – section deleted]

4.5.8 [Intentionally left blank – section deleted]

4.5.8.1 [Intentionally left blank – section deleted]

4.5.8.2 [Intentionally left blank – section deleted]

4.5.8.3 [Intentionally left blank – section deleted]

4.5.9 [Intentionally left blank – section deleted]

4.5.9.1 [Intentionally left blank – section deleted]

4.5.9.2 [Intentionally left blank – section deleted]

4.5.10 [Intentionally left blank – section deleted]

4.5.10.1 [Intentionally left blank – section deleted]

4.5.10.2 [Intentionally left blank – section deleted]

4.5.11 [Intentionally left blank – section deleted]

4.5.12 [Intentionally left blank – section deleted]

5. The IESO

5.1 Responsibility for Market Rules

5.1.1 The body corporate responsible for the administration and supervision of the *market rules* is the *IESO*.

5.2 Objects of the IESO

5.2.1 The objects of the *IESO* are specified in subsection 6(1) of the *Electricity Act, 1998*.

5.2.1.1 [Intentionally left blank – section deleted]

5.2.1.2 [Intentionally left blank – section deleted]

5.2.1.3 [Intentionally left blank – section deleted]

5.2.1.4 [Intentionally left blank – section deleted]

5.2.1.5 [Intentionally left blank – section deleted]

5.2.1.6 [Intentionally left blank – section deleted]

5.2.1.7 [Intentionally left blank – section deleted]

5.3 Functions of the IESO

5.3.1 The functions, powers and authority of the *IESO* in relation to the administration and supervision of the *market rules* include:

5.3.1.1 supervising, administering and enforcing the *market rules*;

5.3.1.2 operating the markets related to electricity and *ancillary services* established under the *market rules*;

5.3.1.3 instituting and ensuring through the administration, supervision and enforcement of the *market rules* the effective and efficient implementation of the rules and standards contained in the *market rules*;

5.3.1.4 collecting information and statistics and publishing reports and information relating to the performance of the *IESO-administered markets*;

5.3.1.5 administering the ongoing development of, and *amendments* to, the *market rules*;

5.3.1.6 establishing power system *reliability standards* and maintaining power system *reliability*;

5.3.1.7 undertaking its coordination of power system planning responsibilities;

5.3.1.8 authorizing persons to participate in the *IESO-administered markets* and to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid*;

5.3.1.9 undertaking monitoring, surveillance and investigation of activities in the *IESO-administered markets* and the conduct of *market participants*; and

5.3.1.10 liaising with other bodies having regulatory functions with respect to the *IESO-administered markets* and the *IESO-controlled grid*, such as the *Ontario Energy Board* and the federal Competition Bureau,

the whole of which in accordance with the *market rules*, the by-laws and *licence* of the *IESO* and *applicable law*.

5.4 Compliance with Market Rules

5.4.1 The *IESO* is bound to comply with, observe and perform any duties and obligations imposed on the *IESO* by the *market rules*.

6. Market Participants

6.1 Classes of Market Participants

6.1.1 The classes of *market participants* are described in section 2 of Chapter 2.

6.2 Third Party Rights or Benefits

6.2.1 Unless otherwise expressly stated in the *market rules* or the *Electricity Act, 1998,* a person other than the *IESO* who is not a *market participant* is not entitled to any rights or benefits under the *market rules*.

6.3 Compliance with Market Rules

6.3.1 Subject to the terms of its *licence* and to the *Electricity Act, 1998,* the *Ontario Energy Board Act, 1998* and to any regulations enacted under those *Acts*, each *market participant* is bound to comply with, observe and perform any duties and obligations imposed on the *market participant* by the *market rules.*

6.3.2 Except as otherwise provided in these *market rules* or in any standard, policy, guideline, procedure or other document established by the *IESO* pursuant to these *market rules,* a *market participant* may use such information systems, communication systems, business processes, personnel, service providers or other agents as the *market participant*, in its sole discretion, considers appropriate for the purpose of assisting in the performance of its obligations under these *market rules* and under such standard, policy, guideline, procedure or other document provided that, as between the *IESO* and the *market participant*:

6.3.2.1 the *market participant* shall be bound by and fully responsible for all acts or omissions of its personnel, service providers or other agents; and

6.3.2.2 the *market participant* shall remain solely responsible and liable to the *IESO* for the due performance of such obligations.

7. Interpretation and Rules of Construction

7.1 General

7.1.1 In the *market rules*, unless the context otherwise requires:

7.1.1.1 words importing the singular include the plural and vice versa;

7.1.1.2 words importing a gender include any gender;

7.1.1.3 when italicized, other parts of speech and grammatical forms of a word or phrase defined in the *market rules* have a corresponding meaning;

7.1.1.4 an expression importing a natural person includes any company, partnership, trust, joint venture, association, corporation or other private or public body corporate, any government agency or body politic or collegiate, and any other entity or body or class of entity or body designated by regulation made pursuant to the *Electricity Act, 1998* as coming within the definition of the word "person";

7.1.1.5 a reference to a thing includes a part of that thing;

7.1.1.6 a reference to a Chapter, section, provision, condition, part or appendix is to a Chapter, section, provision, condition, part or appendix of the *market rules*;

7.1.1.7 a reference in a Chapter of the *market rules* to a section is to a section of that Chapter;

7.1.1.8 a reference to any statute, regulation, proclamation, order in council, ordinance, by-law, resolution, rule, order or directive includes all statutes, regulations, proclamations, orders in council, ordinances, by-laws or resolutions, rules, orders or directives varying, consolidating,

re-enacting, extending or replacing it and a reference to a statute includes all regulations, proclamations, orders in council, rules and by-laws of a legislative nature issued under that statute;

7.1.1.9 a reference to a document or provision of a document, including the *market rules* or a provision of the *market rules*, includes an amendment or supplement to, or replacement or novation of, that document or that provision of that document, as well as any exhibit, schedule, appendix or other annexure thereto;

7.1.1.10 a reference to a person includes that person's executors, administrators, successors, substitutes (including, but not limited to, persons taking by novation) and permitted assigns;

7.1.1.11 a reference to a body (including, without limitation, an institute, association or authority), whether statutory or not, which ceases to exist or whose functions are transferred to another body is a reference to the body which replaces it or which substantially succeeds to its powers or functions;

7.1.1.12 a reference to sections of the *market rules* separated by the word "to" (i.e., "sections 1.1 to 1.4") shall be a reference to the sections inclusively;

7.1.1.13 a reference to a time:

a. without the qualification "EST" is a reference to eastern time, which is the prevailing eastern standard or eastern daylight time in the Province of Ontario;

b. followed by the qualification "EST" is a reference to eastern standard time in the Province of Ontario; and

c. without the qualification "am", "a.m.", "pm" or "p.m." is a reference to time based on a 24-hour clock; and

7.1.1.14 a reference to a month, calendar month, year or calendar year shall mean the period that commences the first hour of the first *trading day* that starts in such month or year and terminates the last hour of the last *trading day* that commences in such month or year.

7.1.1.15 [Intentionally left blank – section deleted]

7.2 Headings

7.2.1 Headings in the *market rules* are inserted for convenience of reference only and shall not affect the interpretation of the *market rules*, nor shall they be construed as indicating that all of the provisions of the *market rules* relating to any particular topic are to be found in any particular Chapter, sub-Chapter, section, subsection, clause, provision, part or appendix.

7.3 Shall, Must and May

7.3.1 The words "shall" and "must" shall be construed as imperative and the word "may" shall be construed as permissive.

7.4 Explanatory Notes

7.4.1 Any provision in this document which is indicated as being an "explanatory note" or a "rule note" shall be deemed not to form a part of the *market rules.* Such explanatory notes or rule notes are inserted for convenience only and shall not affect the interpretation of the *market rules* nor be binding on the *IESO* or on any *market participant*.

7.5 Computation of Time

7.5.1 In the computation of time under these *market rules*, unless a contrary intention appears, if there is a reference to a number of days between two events, they are counted by excluding the day on which the first event happens and including the day on which the second event happens.

7.5.2 In the computation of time under Chapters 2, 3, 6 and 10, unless a contrary intention appears, if the time for doing any act or thing expires on a day which is not a *business day*, the act or thing may be done on the next day that is a *business day.*

7.6 IESO Delegates

7.6.1 Delegation by the *IESO* of its powers and duties under these *market rules* shall be governed by the provisions of the *Governance and Structure By-law*.

7.6A Forms, Policies, Guidelines and Other Documents

7.6A.1 Forms, policies, guidelines and other documents, including but not limited to *market manuals* designed, created, developed, established or implemented by the *IESO* or a panel established by the *IESO* shall be interpreted in accordance with

the *market rules* and the *Electricity Act, 1998*. Where there is any inconsistency between the *market rules* and a form, policy, guideline or other document, including but not limited to a *market manual*, the *market rules* shall prevail to the extent of the inconsistency.

7.7 Other Documents

7.7.1 Subject to section 7.7.4, and unless the context otherwise requires, where reference is made in the *market rules* to the design, creation, development, establishment or implementation of policies, guidelines and other documents by the *IESO* or a panel established by the *IESO*, such policies, guidelines and other documents shall not come into force until adopted by the *IESO Board, published* and notice thereof provided in accordance with section 7.7.2. The *IESO Board* may enter into such consultations, seek such advice and assistance and request such input from one or more persons as the *IESO Board* determines appropriate prior to adopting such policies, guidelines and other documents provided that the *IESO Board* retains the sole discretion to adopt such policies, guidelines and other documents in such form as the *IESO Board* determines appropriate. For certainty, any reference to "other documents" in section 7.7 shall not include forms or *market manuals*.

7.7.2 The policies, guidelines and other documents referred to in section 7.7.1 once adopted by the *IESO Board*, and forms and *market manuals* once prepared by the *IESO* shall be *published* by the *IESO* and notice thereof shall be provided to all *market participants*. The *IESO* and each *market participant* shall thereafter be bound to comply with the provisions of any such policies, guidelines, other documents and the *market manuals*.

7.7.2A The *IESO* shall establish a procedure which shall include but not be limited to processes for the stakeholdering of *market manuals* when the *market manuals* are created and for any subsequent amendments.

7.7.3 The *IESO Board* or a committee of the *IESO Board* established for that purpose may, from time to time, amend, and the *IESO Board* may from time to time replace or repeal, any policies, guidelines and other documents referred to in section 7.7.1. The procedures set forth in sections 7.7.1 and 7.7.2 shall apply equally to any amendment, replacement or repeal of such policies, guidelines and other documents and any reference in such sections to the *IESO Board* shall, with respect to the amendment of such policies, guidelines and other documents be deemed to include a reference to a committee of the *IESO Board* established for that purpose.

7.7.4 Any policy, guideline and other document required by the *market rules* to be implemented as an *amendment* to the *market rules* shall be implemented in accordance with the procedures set forth in section 4 of Chapter 3. Any policy, guideline and other document referred to in section 7.7.1 or in the *market manuals* which, by virtue of its prohibitive or mandatory character or its importance to the efficient operation of the *IESO-administered markets* or the *reliable* operation of the *IESO-controlled grid*, should have a legislative character shall be implemented by the *IESO* as an *amendment* to the *market rules.*

7.8 Currency

7.8.1 All references in:

7.8.1.1 the *market rules*;

7.8.1.2 any form, policy, guideline or other document referred to in section 7.7.1 or 7.7.3, including but not limited to all *market manuals*;

7.8.1.3 a *settlement statement*; or

7.8.1.4 an *invoice*,

to a monetary amount are expressed in Canadian dollars.

7.8.2 Any payment required to be made by or to the *IESO* or by or to a *market participant* pursuant to any of the documents referred to in sections 7.8.1.1 to 7.8.1.4 shall be made in Canadian dollars.

8. Notice, Notification, Service and Filing

8.1 Provision of Notice

8.1.1 Subject to section 8.3, and unless a contrary intention appears, notice is properly given, notification is properly made and service, filing, issuance and submission is properly effected under the *market rules*:

8.1.1.1 by courier or other form of personal delivery;

8.1.1.2 by prepaid first class mail addressed to the person at the address for service (if any) supplied by the person to the sender or, where the

person is a *market participant*, to the address shown for that person in the list of *market participants* maintained by the *IESO* pursuant to section 3.1.10 of Chapter 2 or, where the person is the *IESO*, to the registered office of the *IESO*; or

8.1.1.3 by facsimile or electronic mail to a number or reference which corresponds with the address referred to in section 8.1.1.2.

8.2 Time of Notice

8.2.1 Subject to section 8.3, and unless a contrary intention appears, notice, notification, service, filing, issuance or submission shall be treated as having been duly given, made or effected to a person by the sender:

8.2.1.1 where given, made or effected by mail in accordance with section 8.1.1.2 to an address in the Province of Ontario, on the fourth *business day* after the day on which it is mailed;

8.2.1.2 where given, made or effected by mail in accordance with section 8.1.1.2 to an address in Canada outside the Province of Ontario or to an address in the United States, on the sixth *business day* after the day on which it is mailed;

8.2.1.3 where given, made or effected by mail in accordance with section 8.1.1.2 to an address outside Canada or the United States, on the twentieth *business day* after the day on which it is mailed;

8.2.1.4 where given, made or effected by facsimile in accordance with section 8.1.1.3 and a complete transmission report is issued from the sender's facsimile transmission equipment:

a. where notice, notification, service, filing or submission is of the type in relation to which the addressee is obliged to monitor the receipt by facsimile outside of, as well as during, business hours, on the day and at the time of transmission as indicated on the sender's facsimile transmission report; and

b. in all other cases, on the day and at the time of transmission as indicated on the sender's facsimile transmission report, if a *business day* or, if the transmission is on a day which is not a *business day* or is after 5:00 pm (addressee's time), at 9:00 am on the following *business day*;

8.2.1.5 Where given, made or effected by electronic mail in accordance with section 8.1.1.3:

a. where notice, notification, service, filing or submission is of a type in relation to which the addressee is obliged to monitor receipt by electronic mail outside of, as well as during, business hours, on the day and at the time when the notice or notification is recorded by the sender's electronic communication system as having been first received at the electronic mail destination; and

b. in all other cases, on the day and at the time when the notice, notification or document or other material served, filed or submitted is recorded by the sender's electronic communications system as having been first received at the electronic mail destination, if a *business day*, or if that time is after 5:00 pm (addressee's time) or the day is not a *business day*, at 9:00 am on the following *business day*; or

8.2.1.6 in any other case, when the person actually receives the notice, notification or document or other material served, filed or submitted.

8.3 Notice of Directions and Orders

8.3.1 Unless a contrary intention appears, instructions, directions and orders of the *IESO* may be given or issued to *market participants*:

8.3.1.1 in accordance with sections 8.1 or 8.2;

8.3.1.2 by voice communication, in which case the instruction, direction or order shall be deemed validly given or issued at the time of communication.

9. Publication

9.1.1 Subject to section 9.1.2, where any document or information is required by the *market rules*, *applicable law* or the by-laws or *licence* of the *IESO* to be *published* by the *IESO* or, in the case of the *market rules*, to be published by the *Minister*, *publication* shall be effected by placing the document or information on the public *IESO* web site. The document or information shall be deemed to be *published* when the document or information has been so placed.

9.1.2 Where the *market rules*, *applicable law* or the by-laws or *licence* of the *IESO* prescribe a mode of publication other than that described in section 9.1.1 in respect of a specified document or information, the *IESO* shall, in addition to complying with section 9.1.1 comply with the publication requirement applicable to such document or information as is so prescribed. In such a case, the document

or information shall be deemed to be published on the date on which the prescribed publication requirement has been satisfied.

10. [Intentionally left blank]

10.1.1 [Intentionally left blank]

10.1.2 [Intentionally left blank]

10A. General Conduct

10A.1 *Market participants* and the *IESO* shall not directly or indirectly engage or attempt to engage in conduct, alone or with another person, that they know, or ought reasonably to know:

10A.1.1 exploits the *IESO-administered markets*, including by, without limitation, exploiting any gap or defect in the *market rules*;

10A.1.2 circumvents any of the *market rules*;

10A.1.3 manipulates any of the *IESO-administered markets*, including by, without limitation, manipulating the determination of a *settlement amount*;

10A.1.4 undermines through any means the ability of the *IESO* to carry out its powers, duties or functions under the *Electricity Act, 1998* or the *market rules*; or

10A.1.5 interferes with the determination of a *market price* or *dispatch* outcome by competitive market forces.

10A.2 Without limiting the availability of any defences that a *market participant* may have with respect to conduct set out in section 10A.1, a *market participant* will not have violated section 10A.1 where it establishes that its conduct was entirely or predominantly caused by:

10A.2.1 a procurement contract as defined in the *Electricity Act, 1998*; or;

10A.2.2 an order of the *Ontario Energy Board* made in accordance with s. 78.1 of the *Ontario Energy Board Act, 1998*.

10A.3 For the purposes of this section 10A, "conduct" includes acts and omissions, but with respect to the *OPA* and *OEFC* only includes acts or omissions in their capacity as *market participants*, and with respect to the *IESO* does not include:

10A.3.1 market design or implementing government policy; and

10A.3.2 the development of the *market rules*, *market manuals* and policies, guidelines, or other documents referenced in section 7.7 of Chapter 1.

11. Information Disclosure

11.1 Disclosure Must be Made Where Required by Market Rules

11.1.1 *Market participants* shall disclose or provide to the *IESO* and/or to other *market participants,* and the *IESO* shall disclose or provide to *market participants*, such information as is required to be disclosed or provided pursuant to the *market rules*. Such information shall be disclosed or provided within the time specified in, and in the form and manner required by, the relevant provisions of the *market rules*. Where no time is specified in relation to the disclosure or provision of specific information, the information shall be disclosed or provided within a reasonable time.

11.2 No Misleading or Deceptive Information

11.2.1 Information disclosed or provided by a *market participant* to the *IESO* and/or to other *market participants* or by the *IESO* to *market participants* pursuant to the *market rules* shall be, to the best of the disclosing person's knowledge, true, correct and complete at the time at which such disclosure or provision is made. Neither the *IESO* nor *market participants* shall knowingly or recklessly disclose or provide information pursuant to the *market rules* that, at the time and in light of the circumstances in which such disclosure or provision is made, is misleading or deceptive or does not state a fact that is required to be stated or that is necessary to make the statement not misleading or deceptive.

11.3 Correction of Incorrect Information

11.3.1 Where a *market participant* or the *IESO* discovers that any information previously disclosed or provided by it to any person pursuant to the *market rules* was, at the time at which it was disclosed or provided, or becomes untrue, incorrect, incomplete, misleading or deceptive, the disclosing person shall immediately rectify the situation and disclose or provide the true, correct, complete, not misleading or not deceptive information to the person to whom the original or currently untrue, incorrect, incomplete, misleading or deceptive information had been disclosed or provided.

11.4 Use of Information by the IESO

11.4.1 Subject to the provisions of sections 3 and 5 of Chapter 3, the *IESO* and any panel established by the *IESO* is entitled to use any data or information obtained in pursuance of the *IESO*'s or the panel's powers, functions or duties under the *market rules*, *applicable law* or the by-laws or *licence* of the *IESO.* The *IESO* may use such information in connection with or to initiate processes provided for in the *market rules* including, but not limited to:

11.4.1.1 a process to *amend* the *market rules* pursuant to section 4 of Chapter 3; or

11.4.1.2 a process to enforce compliance with the *market rules* pursuant to section 6 of Chapter 3.

12. Interpretation Bulletins

12.1.1 [Intentionally left blank]

12.1.2 [Intentionally left blank]

12.1.3 Where the *IESO* receives a request from any person, including a member of a panel established by the *IESO*, a *market participant* or the *IESO Board*, seeking a clarification or posing a question as to the interpretation, application or implementation of a *market rule*, the *IESO* may refer the matter to the *technical panel* and the *technical panel* shall provide such clarification or the answer to such question to the *IESO.*

12.1.4 The *IESO* may, from time to time, either on its own initiative or upon receipt from the *technical panel* of a material clarification of, or answer to, a question concerning the interpretation, application or implementation of a *market rule*,

publish and give notice of bulletins as to the interpretation, application or implementation of a *market rule*.

12.1.5 A bulletin *published* pursuant to section 12.1.4 shall be binding on the *IESO*, provided that:

12.1.5.1 none of the relevant *market rules* are thereafter *amended*;

12.1.5.2 there is thereafter no amendment to any relevant provisions of the *Electricity Act, 1998;* and

12.1.5.3 the *IESO* has been provided with all relevant facts in respect of which the interpretation or clarification has been requested and all such facts were true at the time the interpretation or clarification was made.

13. Liability and Indemnification

13.1 Liability of IESO

13.1.1 Except as required by section 13.1.2 or as otherwise provided in these *market rules,* the *IESO* shall not be liable for any claims, losses, costs, liabilities, obligations, actions, judgements, suits, expenses, disbursements or damages of a *market participant* whatsoever, howsoever arising and whether as claims in contract, claims in tort (including but not limited to negligence) or otherwise, arising out of any act or omission of the *IESO* in the exercise or performance or the intended exercise or performance of any power or obligation under these *market rules* or under any policy, guideline or other document referred to in section 7.7 or any *market manual.*

13.1.2 Subject to section 13.1.4, the *IESO* shall indemnify and hold harmless a *market participant* and the *market participant's* directors, officers and employees from any and all claims, losses, liabilities, obligations, actions, judgements, suits, costs, expenses, disbursements and damages incurred, suffered, sustained or required to be paid, directly or indirectly, by, or sought to be imposed upon, the *market participant* or its directors, officers or employees to the extent that such claims, losses, liabilities, actions, judgements, suits, costs, expenses, disbursements or damages arise out of any willful misconduct by or any act or omission that constitutes gross neglience of the *IESO* in the exercise or performance or the intended exercise or performance of any power or obligation under these *market rules* or under any policy, guideline or other document referred to in section 7.7 or any *market manual*.

13.1.3 For the purposes of section 13.1.2, an act or omission of the *IESO* effected in compliance with these *market rules* or with the provisions of any policy, guideline or other document referred to in section 7.7 or any *market manual* shall be deemed not to constitute willful misconduct or gross negligence.

13.1.4 Except as otherwise provided in these *market rules* other than in this section 13, in no event shall the *IESO* be liable to indemnify and hold harmless a *market participant* or the *market participant's* directors, officers or employees from or in respect of:

13.1.4.1 any indirect or consequential loss or incidental or special damages including, but not limited to, punitive damages; or

13.1.4.2 any loss of profit, loss of contract, loss of opportunity or loss of goodwill,

and no *market participant* shall assert or attempt to assert against the *IESO* any claim in respect of any of the losses or damages referred to in sections 13.1.4.1 and 13.1.4.2.

13.1.5 Each *market participant* shall have a duty to mitigate damages, losses, liabilities, expenses or costs relating to any claims for indemnification that may be made by the *market participant* pursuant to section 13.1.2.

13.2 Liability of Market Participants

13.2.1 Except as required by section 13.2.2 or as otherwise provided in these *market rules,* a *market participant* shall not be liable for any claims, losses, costs, liabilities, obligations, actions, judgements, suits, expenses, disbursements or damages of the *IESO* whatsoever, howsoever arising and whether as claims in contract, claims in tort (including but not limited to negligence) or otherwise, arising out of any act or omission of the *market participant* in the exercise or performance or the intended exercise or performance of any power or obligation under these *market rules* or under any policy, guideline or other document referred to in section 7.7 or any *market manual.*

13.2.2 Subject to section 13.2.4, each *market participant* shall indemnify and hold harmless the *IESO,* the *IESO's* directors, officers and employees and any member of a panel established by the *IESO* from any and all claims, losses, liabilities, obligations, actions, judgements, suits, costs, expenses, disbursements and damages incurred, suffered, sustained or required to be paid, directly or indirectly, by, or sought to be imposed upon, the *IESO,* its directors, officers or employees or the member of a panel established by the *IESO* to the extent that such claims, losses, liabilities, actions, judgements, suits, costs, expenses, disbursements or

damages arise out of any willful misconduct by or any negligent act or omission of the *market participant* in the exercise or performance or the intended exercise or performance of any power or obligation under these *market rules* or under any policy, guideline or other document referred to in section 7.7 or any *market manual*.

13.2.3 For the purposes of section 13.2.2, an act or omission of a *market participant* effected in compliance with the *market rules* or with the provisions of any policy, guideline or other document referred to in section 7.7 or any *market manual* shall be deemed not to constitute willful misconduct or a negligent act or omission.

13.2.4 Except as otherwise provided in these *market rules* other than in this section 13, in no event shall a *market participant* be liable to indemnify and hold harmless the *IESO,* the *IESO's* directors, officers or employees or a member of a panel established by the *IESO* from or in respect of:

13.2.4.1 any indirect or consequential loss or incidental or special damages including, but not limited to, punitive damages; or

13.2.4.2 any loss of profit, loss of contract, loss of opportunity or loss of goodwill,

and the *IESO* shall not assert or attempt to assert against a *market participant* any claim in respect of any of the losses or damages referred to in sections 13.2.4.1 and 13.2.4.2.

13.2.5 Nothing in this section 13.2 shall be read as limiting the right of the *IESO* to impose a financial penalty or other sanction including, but not limited to, the issuance of a *suspension order*, a *disconnection order* or a *termination order*, on a *market participant* in accordance with the provisions of these *market rules.*

13.2.6 The *IESO* shall have a duty to mitigate damages, losses, liabilities, expenses or costs relating to any claims for indemnification that may be made by the *IESO* pursuant to section 13.2.2 including, but not limited to, seeking recovery under any applicable policies of insurance to which the *IESO* or the *market participant,* as the case may be, is a beneficiary.

13.3 Force Majeure

13.3.1 Subject to section 13.3.14, the *IESO* shall not be liable to any *market participant* for any failure or delay in the performance of any of its obligations under these *market rules* or under the provisions of any policy, guideline or other document referred to in section 7.7 or any *market manual*, other than the obligation to make payments of money, to the extent that such failure or delay is due to a *force*

majeure event, provided that the *IESO* shall only be excused from performance pursuant to this section 13.3.1:

13.3.1.1 for so long as the *force majeure event* continues and for such reasonable period of time thereafter as may be necessary for the *IESO* to resume performance of the obligation; and

13.3.1.2 where and to the extent that the failure or delay in performance would not have been experienced but for such *force majeure event*.

13.3.2 Subject to section 13.3.14, a *market participant* shall not be liable to the *IESO* for any failure or delay in the performance of any of its obligations under these *market rules* or under the provisions of any policy, guideline or other document referred to in section 7.7 or any *market manual*, other than the obligation to make payments of money, to the extent that such failure or delay is due to a *force majeure event,* provided that the *market participant* shall only be excused from performance pursuant to this section 13.3.2:

13.3.2.1 for so long as the *force majeure event* continues and for such reasonable period of time thereafter as may be necessary for the *market participant* to resume performance of the obligation; and

13.3.2.2 where and to the extent that such failure or delay would not have been experienced but for such *force majeure event*.

13.3.3 Neither the *IESO* nor a *market participant* may invoke a *force majeure event* unless it has given notice in accordance with section 13.3.4 or 13.3.5, respectively.

13.3.4 Where the *IESO* invokes a *force majeure event*, it shall give notice to *market participants* and shall *publish* notice of the *force majeure event* as soon as reasonably practicable but in any event within two *business days* of the date on which the *IESO* becomes aware of the occurrence of the *force majeure event*, which notice shall include particulars of:

13.3.4.1 the nature of the *force majeure event*;

13.3.4.2 the effect that such *force majeure event* is having on the *IESO's* performance of its obligations under these *market rules* or under the provisions of any policy, guideline or other document or referred to in section 7.7 or any *market manual*; and

13.3.4.3 the measures that the *IESO* is taking, or proposes to take, to alleviate the impact of the *force majeure event*.

13.3.5 Where a *market participant* invokes a *force majeure event*, it shall give notice to the *IESO* of the *force majeure event* as soon as reasonably practicable but in any event within two *business days* of the date on which the *market participant* becomes aware of the occurrence of the *force majeure event*, which notice shall include particulars of:

13.3.5.1 the nature of the *force majeure event*;

13.3.5.2 the effect that such *force majeure event* is having on the *market participant's* performance of its obligations under these *market rules* or under the provisions of any policy, guideline or other document referred to in section 7.7 or any *market manual*; and

13.3.5.3 the measures that the *market participant* is taking, or proposes to take, to alleviate the impact of the *force majeure event*.

13.3.6 Subject to section 13.3.7, where the *IESO* or a *market participant* invokes a *force majeure event*, it shall use all reasonable endeavours to mitigate or alleviate the effects of the *force majeure event* on the performance of its obligations under these *market rules*.

13.3.7 The settlement of any strike, lockout, restrictive work practice or other labour disturbance constituting a *force majeure event* shall be within the sole discretion of the *IESO* or the *market participant*, as the case may be, involved in such strike, lockout, restrictive work practice or other labour disturbance and nothing in section 13.3.6 shall require the *IESO* or the *market participant*, as the case may be, to mitigate or alleviate the effects of such strike, lockout, restrictive work practice or other labour disturbance.

13.3.8 Where the *IESO* invokes a *force majeure event,* it shall notify *market participants* and shall as soon as practicable *publish* notice of any material change in the information contained in the notice referred to in section 13.3.4 or in any previous notice given and *published* pursuant to this section 13.3.8.

13.3.9 Where a *market participant* invokes a *force majeure event*, it shall as soon as practicable notify the *IESO* of any material change in the information contained in the notice referred to in section 13.3.5 or in any previous notice given pursuant to this section 13.3.9.

13.3.10 Where the *IESO* invokes a *force majeure event*, it shall give notice to *market participants* and shall *publish* notice of the cessation of the *force majeure event* and of the cessation of the effects of such *force majeure event* on the *IESO*'s performance of its obligations under these *market rules* or under the provisions of

any policy, guideline or other document referred to in section 7.7 or any *market manual*.

13.3.11 Where a *market participant* invokes a *force majeure event*, it shall give notice to the *IESO* of the cessation of the *force majeure event* and of cessation of the effects of such *force majeure event* on the *market participant's* performance of its obligations under these *market rules* or under the provisions of any policy, guideline or other document referred to in section 7.7 or any *market manual*.

13.3.12 The *IESO* shall *publish* any notice provided to it pursuant to section 13.3.5, 13.3.9 or 13.3.11.

13.3.13 Nothing in this section 13.3 shall be read as limiting the right of the *IESO* to impose on a *market participant* a sanction, other than a financial penalty, including but not limited to the issuance of a *suspension order*, a *disconnection order* or a *termination order*, in accordance with the provisions of these *market rules.*

13.3.14 Nothing in this section 13.3 shall excuse the *IESO* or a *market participant* from performing any of their respective obligations contained in:

13.3.14.1 those provisions of these *market rules* that govern the *IESO* and the *market participant* during an *emergency* or while the *IESO-controlled grid* is in a *high-risk operating state* or in an *emergency operating state*;

13.3.14.2 those provisions of any policy, guideline or other document referred to in section 7.7 or any *market manual* that govern the *IESO* and the *market participant* during an *emergency* or while the *IESO-controlled grid* is in a *high-risk operating state* or in an *emergency operating state*;

13.3.14.3 the *Ontario electricity emergency plan*;

13.3.14.4 the *market participant's emergency preparedness plan*;

13.3.14.5 the *Ontario power system restoration plan*; or

13.3.14.6 the *market participant's restoration participant attachment*,

during an *emergency* or while the *IESO-controlled grid* is in a *high-risk operating state* or in an *emergency operating state*.

13.4 Contractual Liability

13.4.1 The liability and indemnification provisions of sections 13.1 and 13.2 and, where applicable, of any other section of these *market rules* other than this section 13, and the *force majeure* provisions of section 13.3 shall apply to any agreement or contract referred to in these *market rules* or in any policy, guideline or other document referred to in section 7.7 or any *market manual* to which the *IESO* and a *market participant* are parties or to the terms of which the *IESO* and a *market participant* are bound and to all acts or omissions of the *IESO* or the *market participant* in the exercise or performance or the intended exercise or performance of any power or obligation under such agreement, contract, policy, guideline or other document referred to in section 7.7 or any *market manual*. In the event of an inconsistency between such liability, indemnification and *force majeure* provisions and the liability, indemnification and *force majeure* provisions of such agreement, the liability and indemnification provisions of sections 13.1 and 13.2 and, where applicable, of any other section of these *market rules*, and the *force majeure* provisions of section 13.3 shall prevail to the extent of the inconsistency.

14. Exemptions

14.1 Scope of Exemptions

14.1.1 As provided in the *Electricity Act, 1998* an *exemption applicant* may apply to the *IESO* for an *exemption* from the application of any obligation or standard which is or may be imposed upon the *exemption applicant* or in respect of the *exemption applicant's facilities* or equipment pursuant to these *market rules, market manuals* or to any standard, policy or procedure established by the *IESO* pursuant to these *market rules*.

14.1.2 In this section 14, a reference to an *exemption applicant* shall, where the context so requires, be deemed to include a reference to an *exemption applicant* to whom an *exemption* has been granted by the *IESO Board*.

14.2 Application Process

14.2.1 An *exemption applicant* shall apply for an *exemption* in accordance with the practices and procedures established by the *IESO Board.*

14.3 Effect of Exemption and Monitoring

14.3.1 Failure by an *exemption applicant* to comply with any of the terms and conditions of an *exemption* imposed pursuant to an order of the *IESO Board*, including without limitation any amendments to such terms and conditions, shall constitute a breach of the *market rules*.

14.3.2 An *exemption applicant* to whom an *exemption* has been granted shall from time to time provide to the *IESO* such information as the *IESO* may request for the purposes of monitoring:

14.3.2.1 compliance by the *exemption applicant* with any terms and conditions of the *exemption*; and

14.3.2.2 the progress of implementation of the *exemption* plan forming part of the *exemption application*, as such *exemption* plan may be amended from time to time with the concurrence of the *IESO Board.*

14.4 Reconsideration, Removal or Transfer of Exemptions

14.4.1 Procedures for the reconsideration, removal or transfer of *exemptions* are included in the practices and procedures referred to in section 14.2.1.

14.5 Costs

14.5.1 Where the *IESO Board* has established and included in the practices and procedures referred to in section 14.2.1 the manner in which the *IESO* will recover from each *exemption applicant* the costs of processing its *exemption application* and, where a panel of the *IESO Board* so decides as a term or condition of the *exemption*, an *exemption applicant* other than the *IESO* shall submit to the *IESO* such costs, commit to the *IESO* in such form as the *IESO* considers appropriate to pay such costs, or both, in the manner specified in the practices and procedures referred to in section 14.2.1.

14.5.2 Where the removal or reconsideration of an *exemption* granted to a *pre-existing facility or equipment* prior to *market commencement date* was prompted as a result of the activities of one or more *market participants* and the *IESO* determines that such *market participant(s)* will benefit from the removal or reconsideration of the *exemption*, unless the costs to be incurred by the *exemption applicant* to comply with the standard of obligation to which the *exemption* relates or with the amended terms and conditions of the *exemption* as the case may be, are recoverable by means of a process or procedure mandated by the *OEB*, costs shall be recovered from each such *market participant* on a pro-rata basis based

upon the *IESO's* assessment of the benefit accruing to each such *market participant* from the removal or reconsideration of the *exemption*. No costs shall be recoverable in respect of the removal or reconsideration of an *exemption* granted after the *market commencement date.*

14.5.3 The costs that may be collected and remitted pursuant to section 14.5.2 shall be calculated by the *IESO* by subtracting from the costs to be incurred by the *exemption applicant* to comply with the standard or obligation to which the *exemption* relates or with the amended terms and conditions of the *exemption*, as the case may be, the value of any benefit determined by the *IESO* as accruing to the *exemption applicant* as a result of its compliance with such standard or obligation or such amended terms and conditions.

14.5.4 Where an *exemption* was granted to a *pre-existing facility or equipment* prior to *market commencement date* but section 14.5.2. is not applicable, the costs will be recovered from one or more of the following classes of *market participants* as determined by the *IESO*:

14.5.4.1 all *market participants* on a pro-rata basis based upon their respective allocated quantities of *energy* withdrawn at all *delivery points* determined in accordance with Chapter 9, during such period as may be specified by the *IESO*;

14.5.4.2 all *market participants* on a pro-rata basis based upon their respective allocated quantities of *energy* injected at all *delivery points* , determined in accordance with Chapter 9, during such period as may be specified by the *IESO*;

14.5.4.3 all *market participants* on a pro-rata basis based upon their respective allocated quantities of *energy* withdrawn at all *intertie* metering points, determined in accordance with Chapter 9, during such period as may be specified by the *IESO*; and

14.5.4.4 all *market participants* on a pro-rata basis based on their respective allocated quantities of *energy* injected at all intertie metering points, determined in accordance with Chapter 9, during such period as may be specified by the *IESO*.

14.6 Need for Rule Amendment

14.6.1 Where the *IESO* determines that the benefit of an *exemption* should be extended to all *market participants* or persons or to a class of *market participants* or persons the *IESO* may:

14.6.1.1 where the *exemption* was granted prior to the date on which section 4 of Chapter 3 comes into force, recommend to the *IESO Board* that it advise the *Minister* that an *amendment* to the *market rules* be made accordingly; or

14.6.1.2 where the *exemption* was granted after the date on which section 4 of Chapter 3 comes into force, recommend to the *IESO Board* that the *amendment* process set forth in section 4 of Chapter 3 be initiated with a view to *amending* the *market rules* accordingly.

Exhibit “L”

Chapter 3 of the IESO Market Rules issued May 1, 2023

Exhibit “L”

to the Affidavit of Robin Doolittle

Sworn before me on October 29, 2025, in accordance with O. Reg. 431/20,
Administering Oath or Declaration Remotely



Commissioner for Taking Affidavits
(or as may be)

October 29, 2025

Keith Edward Hickey, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.

Expires June 24, 2027.

Market Rules

Chapter 3
Administration, Supervision, Enforcement

Connecting Today.
Powering Tomorrow.

Public

Issue Date: May 1, 2023

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1. Introduction

1.1 Scope of Chapter

1.1.1 This Chapter sets forth:

1.1.1.1 the dispute resolution mechanism applicable to certain disputes arising under the *market rules*;

1.1.1.2 the manner in which market monitoring and surveillance responsibilities will be carried out;

1.1.1.3 the procedures pursuant to which the *market rules* may be amended;

1.1.1.4 the procedures which govern the protection, use and disclosure of *confidential information* by the *IESO* and *market participants*; and

1.1.1.5 the manner in which the *IESO* will monitor, assess and enforce compliance with the *market rules*.

2. Dispute Resolution

2.1 Interpretation and General Procedural Provisions

2.1.1 The provisions of this section 2 shall be liberally construed to secure the most expeditious, just and least expensive determination on its merits of every proceeding conducted hereunder.

2.1.2 Where no procedures are provided for in this section 2 or the applicable *market manual*, a *mediator* or an *arbitrator* may do whatever is reasonably necessary and permitted by law to enable the effective mediation or adjudication of any matter before the *mediator* or the *arbitrator*.

2.1.3 The parties to a dispute may agree to dispense with, supplement or vary the application of all or any part of the provisions of sections 2.5.3A to 2.7. A *mediator,* an *arbitrator* or the *secretary* may, in the context of the resolution or the attempted resolution of a specific dispute pursuant to this section 2, dispense with, supplement or vary the application of all or any part of the provisions of sections 2.5.3A to 2.7, including as to any prescribed time periods, if special circumstances or the public interest require, or with the consent of the parties to the dispute. The *secretary's* authority to dispense with, supplement or vary the application of all or any part of the provisions of sections 2.5.3A to 2.7 lapses with respect to a particular dispute once a *mediator* or *arbitrator* is appointed in respect of that dispute.

2.1.4 The *IESO* shall from time to time *publish* and notify *market participants* of the address of the *secretary* for filing purposes.

2.1.5 Unless otherwise specified in this section 2 or otherwise directed by the *secretary*, a *mediator* or an *arbitrator*, only one copy of any document is required to be served or filed.

2.1.6 The following provisions of the *Arbitration Act, 1991* do not apply to any proceeding conducted under this section:

2.1.6.1 subsection 10(1)(b);

2.1.6.2 subsection 13(1)2;

2.1.6.3 subsection 23(1);

2.1.6.4 section 24;

2.1.6.5 subsections 25(3) to 25(5);

2.1.6.6 sections 34, 37, 39, 45, 48 and 53;

2.1.6.7 subsections 54(5) and 54(6); and

2.1.6.8 sections 55 and 56, insofar as they may be applicable to the fees payable to an *arbitrator* and to the extent that such fees have been approved by the *Ontario Energy Board*.

2.2 Application

2.2.1 Subject to sections 2.2.3 and 3.8 and to section 8.8.1 of Chapter 2, the dispute resolution regime provided for in this section 2 shall apply to:

2.2.1.1 any dispute between the *IESO* and any *market participant* which arises under the *market rules*, *market manuals* or any standard, policy or procedure established by the *IESO* pursuant to these *market rules*, including with respect to any alleged violation or breach thereof, whether or not specifically identified in the *market rules* as a dispute to which this section 2 applies;

2.2.1.1A a contested matter pursuant to section 6.2B.5 and section 6.2B.9, except as otherwise provided in section 6.2B;

2.2.1.1B a dispute involving an order of the *IESO* issued pursuant to section 6.2B.15, except as otherwise provided in section 6.2B;

2.2.1.2 any denial by the *IESO* of authorization to any person to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, out of or through the *IESO-controlled grid*, as to the denial of such authorization;

2.2.1.3 an application by a *generator* or *electricity storage participant* for compensation pursuant to section 6.7.5 of Chapter 5 in respect of an *outage* rejected by the *IESO*;

2.2.1.4 a reviewable decision;

2.2.1.5 a dispute referred to in section section 6.10.1 of Chapter 9;

2.2.1.6 [intentionally deleted];

2.2.1.7 any dispute between the *IESO*, on the one hand, and any *market participant*, *connection applicant* or *metering service provider*, on the other hand, pursuant to the terms of any agreement or contract referred to in these *market rules* or in any policy, guideline or other document referred to in section 7.7 of Chapter 1 or any *market manual*, unless in respect of a given dispute the agreement or contract or the *licence* of a party to the dispute either provides for an alternative dispute resolution mechanism or provides that the dispute resolution regime provided in this section 2 shall not be applicable;

2.2.1.8 a dispute between *market participants* referred to in section 2.1A.6A of Chapter 9 in respect of the apportionment of *energy* associated with *connection station service* and with site specific losses; and

2.2.1.9 the *IESO's* determination under sections 3.2.5, 3.2.6, and 3.2.7 of Chapter 5 regarding the applicability of *reliability standards*.

2.2.1.10 a dispute referred to in section 10.4.8 of Chapter 6; and

2.2.1.11 a dispute referred to in section 6C.1.5 of Chapter 10.

2.2.2 The dispute resolution regime provided for in this section 2:

2.2.2.1 shall apply to a dispute between *market participants* referred to in section 8.4.3 of Chapter 5; and

2.2.2.2 may also apply to any other disputes between *market participants* where all of the *market participants* which are party to the dispute consent in writing to the application thereof.

2.2.2A A *market participant* that has, pursuant to section 2.2.2.2, consented to the application of the dispute resolution regime provided for in this section 2 may, prior to the date on which the *secretary* takes the action referred to in section 2.6.2.1 or 2.6.2.2, as the case may be, withdraw its consent in the event that a *respondent* to a crossclaim objects to the application of such regime.

2.2.3 The dispute resolution process provided for in this section 2 shall not apply to the following:

2.2.3.1 applications by any person to review a *market rule*, which applications shall be governed by section 4;

2.2.3.2 disputes with respect to a proposal to *amend* or not to *amend* any provision of the *market rules*;

2.2.3.3 disputes between the *IESO* and a *market participant* relating to the quantum of the fees chargeable by the *IESO* to the *market participant* to the extent that such fees have been approved by the *Ontario Energy Board*, unless the dispute relates to the manner of calculation of the fees payable by the *market participant* in any given case;

2.2.3.4 [Intentionally left blank]

2.2.3.5 disputes between the *IESO* and a *market participant* relating to a *suspension order* issued by the *IESO* or to a *termination order* issued by the *IESO*, in respect of which an appeal may be filed with the *Ontario Energy Board* pursuant to section 36 of the *Electricity Act, 1998*;

2.2.3.6 disputes between the *IESO* and a *market participant* to the extent that the *licence* of the *IESO* or of the relevant *market participant* provides for an alternative dispute resolution mechanism;

2.2.3.7 disputes between the *IESO* and a *market participant* relating to the standards, criteria or requirements established by a *standards authority* to the extent that an agreement with the relevant *standards authority* provides for an alternative dispute resolution mechanism;

2.2.3.8 an award of an *arbitrator* made pursuant to this section 2;

2.2.3.9 any dispute with respect to which these *market rules,* other than this section 2, provide for an alternative dispute resolution mechanism;

2.2.3.10 any dispute with respect to which these *market rules,* other than this section 2, provide for the non-application of the dispute resolution process provided for in this section 2;

2.2.3.11 a decision of a panel of the *IESO Board*:

(a) granting or rejecting an *exemption application*;

(b) respecting the terms and conditions of an *exemption*, other than with respect to the quantum of the costs payable by the *exemption applicant* or one or more *market participants* pursuant to Chapter 1, section 14.5;

(c) removing or amending an *exemption* or the terms and conditions thereof, other than with respect to the quantum of the costs referred to in Chapter 1, section 14.5;

(d) approving or denying the transfer of an *exemption*; or

(e) respecting *confidential information* provided to the *IESO* as part of or in respect of an *exemption application* including, without limitation the disclosure thereof; and

2.2.3.12 when considering an *exemption application*, including for certainty a reconsideration or transfer of an *exemption*, a determination or decision by a panel of the *IESO Board* regarding the interpretation of the provisions of any *market rule, market manual* or any standard, policy or procedure established by the *IESO* pursuant to the *market rules*.

2.2.3.13 [Intentionally left blank – section deleted]

2.2.4 Subject to such rights of appeal or review as may be prescribed by *applicable law,* an award of an *arbitrator* made pursuant to this section 2 is final and binding on the parties. Without limiting the generality of the foregoing, but subject to sections 2.2.5 and 3.8 and to section 8.8.1 of Chapter 2, where any dispute of a kind described in section 2.2.1 or 2.2.2 arises, the parties concerned shall comply with the procedures set forth in this section 2 before commencing a civil or other proceeding in relation to the dispute, including but not limited to the filing of an appeal pursuant to subsection 36(1) of the *Electricity Act, 1998*.

2.2.5 Nothing in this section 2 shall prevent a party to a dispute from making application to a court of competent jurisdiction in the Province of Ontario for urgent interlocutory or interim injunctive relief.

2.3 Continuing Obligations and Stay of Orders

2.3.1 Subject to section 2.3.3, where a dispute involves the payment or recovery of monetary amounts due under the *market rules*, the amount shall be due and payable at the time specified for payment under the *market rules* notwithstanding initiation of the dispute resolution process.

2.3.2 Subject to section 2.3.3, initiation of the dispute resolution process referred to in this section 2 does not stay implementation of an order made or a direction given to a *market participant* by the *IESO* pursuant to the *market rules*.

2.3.3 Where a dispute in respect of which the dispute resolution process has been initiated involves the payment of a financial penalty imposed upon a *market participant* by the *IESO* under section 6.2, the obligation of the *market participant* to pay the financial penalty shall be stayed pending the outcome of the dispute resolution process.

2.4 [Intentionally left blank – section deleted]

2.5 Notice of Dispute, Negotiation and Response

2.5.1 The complaining person (the "*applicant*") shall, within the time specified in section 2.5.1A, serve a written notice of the dispute (the "*notice of dispute*") on any *respondent*.

2.5.1A Subject to section 2.5.1B, a *notice of dispute* shall be served:

2.5.1A.1 in the case of an application referred to in section 2.2.1.3, within 20 *business days* of the date of receipt of notice by the *generator* or *electricity storage participant* of rejection by the *IESO* of the *outage* in

respect of which compensation is claimed pursuant to section 6.7.5 of Chapter 5;

2.5.1A.2 in the case of a dispute that involves a *reviewable decision* referred to in section 5.3.9 of Chapter 6, within 20 *business days* of the date of receipt by the *metering service provider* of notice of the revocation of its registration by the *IESO*;

2.5.1A.3 in the case of a dispute referred to in section 6C.1.5 of Chapter 10, within 20 *business days* of the *market participant* receiving the relevant *settlement statement* with the adustments specified in accordance with section 6C of Chapter 10;

2.5.1A.4 in the case of a dispute referred to in section 6.10.1 of Chapter 9, except for those matters identified in section 6.8.12.4 of Chapter 9, within the time specified in section 6.10.2.3 of Chapter 9;

2.5.1A.4A in the case of a dispute referred to in section 2.1A.6A of Chapter 9, within 20 *business days* of the date of receipt of the first *invoice* that reflects the apportionment that is the subject-matter of the dispute;

2.5.1A.4B in the case of a dispute referred to in section 10.4.8 of Chapter 6, within 20 business days of:

(a) the IESO notifying the market participant of the the IESO's determination if the IESO concludes pursuant to section 10.4.5.1 of Chapter 6 that no further action is required; or

(b) receipt of the settlement statement on which the adjustment is reflected if the IESO concludes an adjustment is required pursuant to section 10.4.5.2 of Chapter 6;

2.5.1A.4C in the case of a dispute involving an order, direction, instruction or decision of the *IESO*, including a matter referred to in section 6.8.12.4 of Chapter 9 that involves an order, direction, instruction or decision of the *IESO* relating to a compliance and enforcement action described in section 6 of Chapter 3, issued on or after January 1, 2004 not otherwise addressed by subsections 2.5.1A.1 to 2.5.1A.4A, within two years of the date of receipt of the order, direction, instruction or decision;

2.5.1A.4D in the case where the *market participant* contests the *notice of intention* under section 6.2B.3, within the timelines set out in section

6.2B.3 and the *response to the notice of intention* shall be deemed to constitute the *notice of dispute*;

2.5.1A.4E in the case of a dispute involving one or more orders referred to in section 6.2B.15, within the timelines set out in section 6.2B.16;

2.5.1A.4F 2.5.1A.4F in the case of a dispute referred to in section 7.6.5 of Chapter 7, within 20 *business days* of:

(a) the *IESO* notifying the *market participant* of its determination if the *IESO* determines pursuant to section 7.6.3.2 of Chapter 7 that the *market participant* is not entitled to compensation; or

(b) the receipt of the *settlement statement* on which the compensation is reflected if the *IESO* determines pursuant to section 7.6.3.2 of Chapter 7 that the *market participant* is entitled to compensation;

2.5.1A.4G in the case of matters referred to in section 6.8.12.4 of Chapter 9, except for a compliance and enforcement action described in section 6 of Chapter 3, within 20 *business days* of the *market participant* receiving the relevant *settlement statement* with the adustments specified in accordance with the relevant provision; and

2.5.1A.5 in all other cases, within the applicable limitation period set out in the *Limitations Act, 2002*.

2.5.1B Commencing with *settlement amounts* which were invoiced or should have been invoiced on or after *RSS commencement date* and in regards to sections 2.5.1A.1, 2.5.1A.3, 2.5.1A.4, 2.5.1A.4B, and 2.5.1A.4F, in no circumstance shall a *notice of dispute* be served more than 24 months following the earlier of:

(a) the initial date when the *IESO* would have the right or obligation to settle the transaction, charge or payment that is the subject of the dispute; or

(b) the date on which the IESO issues an invoice in respect of the transaction, charge or payment that is the subject of the dispute.

This section and section 2.5.1A shall apply whether or not the transaction, charge or payment that is the subject of the dispute was capable of being identified or discovered within the time specified in section 2.5.1A and this section 2.5.1B. Notwithstanding the foregoing, where entitlement to a settlement amount is prescribed by applicable law, in no circumstance shall a notice of dispute be served beyond the limitation period, if any, provided pursuant to applicable law.

2.5.2 The *notice of dispute* shall be in such form as may be established by the *IESO,* shall be signed by a person with authority to bind the *applicant* and shall specify, in reasonable detail and to the best of the *applicant*'s knowledge:

2.5.2.1 the nature of and basis for the complaint;

2.5.2.2 the *market rules* in issue;

2.5.2.3 the parties to the dispute and the name of any person having knowledge of or who may be directly affected by the dispute;

2.5.2.4 a concise summary of the facts underlying the dispute;

2.5.2.5 the relief sought and a summary of the grounds for such relief; and

2.5.2.6 any documentation upon which the *applicant* intends to rely in support of its complaint.

2.5.3 [Intentionally left blank – section deleted]

2.5.3A Upon service of a *notice of dispute*, the applicant and the respondent to a notice of dispute shall make good faith efforts to negotiate for a minimum period of thirty days to resolve the dispute between them. In regards to disputes where an *IESO* determination is still pending, as contemplated in sections 6.8.15 of Chapter 9 and section 10.4.8 of Chapter 6, the thirty-day period to resolve the dispute through good faith negotiations shall not commence until the *IESO* has completed its determination. Each person who is a party to a dispute shall, to this end, designate an individual with authority to negotiate the matter in dispute and to participate in such negotiations. The parties to the dispute may conduct the good faith negotiations in any manner they so agree.

2.5.3B Communications made in the course of negotiations are confidential, are made without prejudice and are not subject to voluntary disclosure in any subsequent proceeding or to be voluntarily produced into evidence for any purpose other than as reflected in a settlement agreement.

2.5.3C In the event that a dispute is not settled through good faith negotiations, a party may file with the *secretary,* on written notice served on each other party, a copy of the *notice of dispute,* together with proof of service of the *notice of dispute* on each other party. The *notice of dispute* shall be accompanied by a summary of the *notice of dispute* for *publication* in accordance with section 2.9.2.1.

2.5.4 A *respondent* shall, within ten *business days* of the filing of a *notice of dispute* with the *secretary* under section 2.5.3C, serve a written response (the "*response*")

on the *applicant* and on any *respondent* to a counterclaim or crossclaim identified in the *response*, and shall file with the *secretary* a copy of the *response,* together with proof of service of the *response* on the *applicant* and on any such *respondent*.

2.5.5 The *response* shall be in such form as may be established by the *IESO*, shall be signed by a person with authority to bind the *respondent* and shall specify, in reasonable detail and to the best of the *respondent's* knowledge:

2.5.5.1 the information referred to in sections 2.5.2.1 to 2.5.2.4, to the extent that the *respondent* disagrees with the information relating thereto set forth in the *notice of dispute*;

2.5.5.2 a concise *response* to the allegations made against the *respondent* in the *notice of dispute*;

2.5.5.3 the relief sought, a summary of the grounds for such relief and, where the relief sought includes a counterclaim or crossclaim against the *applicant* or against any other *respondent*, the information referred to in sections 2.5.2.1 to 2.5.2.4 as it pertains specifically to such counterclaim or crossclaim; and

2.5.5.4 any documentation upon which the *respondent* intends to rely in support of its *response*, including as to any counterclaim or crossclaim, and which was not identified by the *applicant*.

2.5.6 The *response* shall be accompanied by a summary of the *response* for *publication* in accordance with section 2.9.2.1.

2.5.6A A *respondent* to a counterclaim or crossclaim shall, within ten *business days* of service of a *response* or of a response to a counterclaim or crossclaim, serve a written response to the counterclaim or crossclaim on the *applicant* and on any other *respondent* and shall file with the *secretary* a copy of the response to the counterclaim or crossclaim, together with proof of service of the response to the counterclaim or crossclaim on the *applicant* and on any other *respondent*, including a *respondent* to a counterclaim or crossclaim identified in the response to the counterclaim or crossclaim.

2.5.6B The response to the counterclaim or crossclaim shall be in such form as may be established by the *IESO*, shall be signed by a person with authority to bind the *respondent* and shall specify, in reasonable detail and to the best of the *respondent's* knowledge:

2.5.6B.1 the information referred to in sections 2.5.2.1 to 2.5.2.4, to the extent that the *respondent* disagrees with the information relating thereto set forth in the *response* containing the counterclaim or crossclaim;

2.5.6B.2 a concise response to the allegations made against the *respondent* in the *response* containing the counterclaim or crossclaim;

2.5.6B.3 the relief sought, a summary of the grounds for such relief and, where the relief sought includes a counterclaim or a crossclaim against the *applicant* or another *respondent*, the information referred to in sections 2.5.2.1 to 2.5.2.4 as it pertains specifically to such counterclaim or crossclaim; and

2.5.6B.4 any documentation upon which the *respondent* intends to rely in support of its response to the counterclaim or crossclaim, including as to any counterclaim or crossclaim, and which was not identified by the *applicant* or by the *respondent* whose *response* contains the counterclaim or crossclaim.

2.5.6C The response to a counterclaim or crossclaim shall be accompanied by a summary of the response for *publication* in accordance with section 2.9.2.1.

2.5.7 Subject to sections 2.1.3 and 2.5.9, the *secretary* shall reject and shall not take any further action with respect to a *notice of dispute*, a *response*, or a response to a counterclaim or crossclaim that does not comply with the provisions of this section 2.5.

2.5.7.1 [Intentionally left blank – section deleted]

2.5.7.2 [Intentionally left blank – section deleted]

Where the *secretary* rejects a *notice of dispute*, a *response* or a response to a counterclaim or crossclaim pursuant to this section 2.5.7, the *secretary* shall so notify the *applicant* and the *respondent* filing the *response* or the response to the counterclaim or crossclaim, as the case may be, and shall provide written reasons for the rejection.

2.5.8 [Intentionally left blank – section deleted]

2.5.9 Where the *secretary* rejects a *response* or a response to a counterclaim or crossclaim pursuant to section 2.5.7:

2.5.9.1 such rejection shall be without prejudice to the right of the *applicant* or the *respondent* whose *response* includes the counterclaim or

crossclaim, as the case may be, to proceed with the resolution of the dispute in accordance with section 2; and

2.5.9.2 where such rejection relates to a *response*, section 2.6.1 shall not apply to the dispute and the *applicant* may following receipt of the notice referred to in section 2.5.7 request that the *secretary* take the action referred to in section 2.7.1.

2.6 Mediation

2.6.1 Subject to sections 2.6.1A and 2.6.1B, no party to a dispute may proceed to arbitration of the dispute until such time as the mediation process described in this section 2.6 has been terminated in accordance with section 2.6.14.

2.6.1A Absent agreement of the parties, section 2.6.1 shall not apply to:

2.6.1A.1 an application by a *generator* or *electricity storage participant* for compensation pursuant to section 6.7.5 of Chapter 5 in respect of an *outage* rejected by the *IESO*;

2.6.1A.2 a dispute referred to in section 6.10.1 of Chapter 9, except those matters described in section 6.8.12.4 of Chapter 9;

2.6.1A.3 a dispute that involves a *reviewable decision* referred to in section 5.3.9 of Chapter 6; or

2.6.1A.4 a dispute referred to in section 2.5.9.2.

2.6.1B Where all of the parties to a dispute so agree, the parties may dispense with mediation in respect of the dispute. In such a case, the parties shall file with the *secretary* a notice of intent to dispense with mediation in such form as may be established by the *IESO*.

2.6.2 Subject to section 2.6.2C, within five *business days* of the filing of a *notice of dispute* in respect of an application to which section 2.6.1A.1 applies or of the earlier of the filing of a *response* or of the expiry of the time for filing a *response* pursuant to section 2.5.4 in all other cases, the *secretary* shall, provided that the *secretary* is satisfied that the dispute is one to which section 2.2.1 or 2.2.2 applies and that the dispute has not been resolved:

2.6.2.1 in the case of a dispute referred to in section 2.6.1A, upon receipt of the notice referred to in section 2.6.1B or upon receipt of the request referred to in section 2.5.9.2, take the action referred to in section 2.7.1 or 2.7.1D, as the case may be; or

2.6.2.2 in any other case, subject to section 2.6.2A, assign one member of the *dispute resolution panel* who is independent of the parties to inquire into and act as *mediator* in respect of the dispute and shall advise the parties to the dispute as to the identity and address for service of the *mediator*.

Where the *secretary* is not satisfied that the dispute is one to which section 2.2.1 or 2.2.2 applies, the *secretary* shall so advise the parties.

2.6.2A Where all of the parties to a dispute so agree, they may appoint a qualified person that is not a member of the *dispute resolution panel* to mediate the dispute. In such a case, the parties shall advise the *secretary* as to the identity and address for service of the *mediator*.

2.6.2B A *mediator* appointed under section 2.6.2A shall not be required in any proceeding to give testimony with respect to information obtained in the course or resolving or attempting to resolve the dispute.

2.6.2C Where a *response* or a response to a counterclaim or crossclaim contains a counterclaim or crossclaim against another *respondent*, the *secretary* shall not take the action referred to in section 2.6.2.1 or 2.6.2.2 until five *business days* following:

2.6.2C.1 the filing of the response to a counterclaim or crossclaim in respect of the last counterclaim or crossclaim filed in the same dispute; or

2.6.2C.2 the expiry of the time for filing a response to a counterclaim or crossclaim pursuant to section 2.5.6A in respect of the last counterclaim or crossclaim filed in the same dispute,

whichever is the earlier.

2.6.3 The *mediator* shall fix a date, time and place for the mediation session, which date shall be no more than seven *business days* from the date of notice of his or her appointment or such later date as may be agreed by each party to the dispute, and shall attempt to assist the parties to resolve their dispute. The *mediator* may continue the mediation session at such times and places as the *mediator* determines in an effort to assist the parties in resolving their dispute.

2.6.4 Each party shall send to the mediation session a representative who has the authority to bind the party.

2.6.5 Prior to participating in a mediation session, the parties must sign and file with the *secretary* an agreement that statements made at a mediation session are

confidential, are made without prejudice and are not subject to voluntary disclosure in any subsequent proceeding or to be voluntarily produced into evidence for any purpose.

2.6.6 Mediation sessions shall be private and there shall be no stenographic record of any mediation session. The parties and their representatives may attend mediation sessions. Other persons may attend only with the permission of all of the parties, with the consent of the *mediator* and upon such conditions including, but not limited to, conditions relating to confidentiality, as the *mediator* determines appropriate.

2.6.7 *Confidential information* disclosed to a *mediator* by the parties or by other persons in the course of the mediation shall not be divulged by the *mediator*. All records, reports or other documents prepared for the mediation and received by a *mediator* while serving in that capacity shall be treated as confidential unless all of the parties to the dispute otherwise agree.

2.6.8 The *mediator* may conduct joint and separate meetings with the parties and make oral and written recommendations for settlement. Recommendations for settlement made, and views expressed by, the *mediator* at such meetings or at a mediation session are confidential and are not subject to voluntary disclosure in any subsequent proceeding and are not voluntarily to be produced into evidence for any purpose.

2.6.9 The *mediator* may, with the consent of the parties, request an agent, employee, officer or director of the *IESO*, or a member of a panel established by the *IESO*, to provide him or her with any information or documentation which is not *confidential information* and which the *mediator* considers relevant to the conduct of the mediation, and the *mediator* shall provide any such information or documentation to the parties in advance of the mediation session at which such information or documentation is to be considered.

2.6.10 The *mediator* may, with the consent of the parties, request an agent, employee, officer or director of the *IESO*, or a member of a panel established by the *IESO*, to provide him or her with any information or documentation pertaining to a party to the dispute which is *confidential information* and which the *mediator* considers relevant to the conduct of the mediation. Such *confidential information* shall not, without the consent of the party to whom the *confidential information* relates, be disclosed by the *mediator* to the other parties to the dispute.

2.6.11 Whenever he or she considers necessary, the *mediator* may, with the consent of the parties and upon such conditions relating to confidentiality as the *mediator* determines appropriate, obtain expert advice concerning technical aspects of the

dispute. Arrangements for obtaining such advice shall be made by the *mediator* or a party, as the *mediator* shall determine.

2.6.12 If an agreement to resolve the dispute is reached through mediation, it shall be reduced to writing, signed by the parties and filed with the *secretary*. The terms of the agreement shall be confidential, provided that if, in the case of a dispute referred to in section 2.2.1, the agreement consists of, embodies or reflects an element which, in the opinion of the *IESO Board*, is an important matter of public policy or interest having regard to the provisions of the *Electricity Act, 1998*, the *IESO* shall *publish* a statement describing such important matter of public policy or interest.

2.6.13 The *mediator* may terminate the mediation by written notice of termination whenever, in the judgement of the *mediator*, further efforts at mediation would not contribute to a resolution of the dispute between the parties. The *mediator* shall provide each party with a copy of the written notice of termination and shall file a copy of the notice of termination with the *secretary*, in each case together with a copy of any agreed statement of fact and/or of issues referred to in section 2.6.15.

2.6.14 The mediation shall be terminated on the earlier of:

2.6.14.1 the date of execution by the parties of the agreement referred to in section 2.6.12;

2.6.14.2 the date of the notice of termination referred to in section 2.6.13; or

2.6.14.3 the date that is ten *business days*, or such longer period as may be agreed by each party to the dispute, from the date of the first mediation session.

2.6.15 If the parties are unable to reach any agreement to resolve the dispute on or prior to the date referred to in section 2.6.14.2 or 2.6.14.3 they shall nonetheless make good faith efforts to arrive at an agreed statement of fact and/or of issues relating to the dispute.

2.6.16 If the parties are unable to reach any agreement to resolve the dispute on or prior to the date referred to in section 2.6.14.3, the *mediator* shall issue a written notice of termination unless the *mediator* has, prior to that date, issued the written notice of termination referred to in section 2.6.13. The *mediator* shall provide each party with a copy of the notice of termination issued pursuant to this section 2.6.16, together with a copy of any agreed statement of fact and/or of issues referred to in section 2.6.15, and file a copy of the foregoing with the *secretary*.

2.6.17 The parties are responsible for their own costs and legal expenses incurred in respect of the mediation. The parties must bear equally the *costs of the mediation* unless otherwise agreed to by the parties.

2.6.18 Upon termination of the mediation, the *mediator* shall file with the *secretary* an invoice containing an itemized statement of the *costs of the mediation*, together with all bills and other supporting documentation relating thereto.

2.6.19 Upon receipt of the invoice referred to in section 2.6.18, the *secretary* shall provide a copy of the invoice to the *IESO* and the *IESO* shall submit an invoice to each of the parties to the mediation in respect of their respective shares of the *costs of the mediation*. Each party shall, within *ten business days* of the date of receipt of such invoice, pay to the *IESO* the amount owing thereunder. Such invoice shall be considered to create an obligation under the *market rules* to pay the amount specified in the invoice and such amount may, without prejudice to any other manner of recovery available at law, be recovered accordingly.

2.6.20 Where a *mediator* dies, resigns or otherwise becomes incapable of acting as *mediator* in respect of a dispute prior to termination of the mediation, subject to section 2.6.2A, the *secretary* shall assign another member of the *dispute resolution panel* to inquire into and act as *mediator* in respect of the dispute. With the consent of the parties to the mediation, the new *mediator* may continue the mediation. In the absence of such consent, the *mediator* shall commence the mediation anew and the time period prescribed in section 2.6.14.3 shall be extended accordingly.

2.7 Arbitration

2.7.1 Subject to section 2.7.1C, within five *business days* of:

2.7.1.1 the earlier of the filing of a *response* or of the expiry of the time for filing a *response* pursuant to section 2.5.4, where the dispute is one to which section 2.6.1A.1, 2.6.1A.2 or 2.6.1A.3 applies;

2.7.1.1A the filing of the request referred to in section 2.5.9.2, where the dispute is one to which that section applies;

2.7.1.2 the filing of a notice of intent to dispense with mediation pursuant to section 2.6.1B, where the dispute is one to which that section applies;

2.7.1.2A the filing of the *notice to elect* referred to section 6.2B.7 electing subsection 6.2B.7.1; or

2.7.1.3 the filing of the notice of termination referred to in section 2.6.13 or 2.6.16, in any other case,

the *secretary* shall, subject to section 2.7.1A, in accordance with the *Governance and Structure By-law* provide the parties with a list of at least three names of members of the *dispute resolution panel* available to arbitrate the dispute. No person who acted as a *mediator* in respect of a dispute may be included on the list of members available to arbitrate the same dispute.

2.7.1A Where all the parties to a dispute so agree, they may appoint a qualified person that is not a member of the *dispute resolution panel* to arbitrate the dispute. In such a case, the parties shall advise the *secretary* as to the identity and address for service of the *arbitrator*.

2.7.1B An *arbitrator* appointed under section 2.7.1A shall not be required in any proceeding to give testimony with respect to information obtained in the course or resolving or attempting to resolve the dispute.

2.7.1C Where a *response* or a response to a counterclaim or crossclaim filed in respect of a dispute to which section 2.6.1A applies contains a counterclaim or crossclaim against another *respondent*, the *secretary* shall not take the action referred to in section 2.7.1.1 until five *business days* following:

2.7.1C.1 the filing of the response to a counterclaim or crossclaim in respect of the last counterclaim or crossclaim filed in the dispute; or

2.7.1C.2 the expiry of the time for filing a response to a counterclaim or crossclaim pursuant to section 2.5.6A in respect of the last counterclaim or crossclaim filed in the dispute,

whichever is the earlier.

2.7.1D Within five *business days* of the filing of a *notice of dispute* in respect of an application to which section 2.6.1A.1 applies, subject to section 2.7.1A, the *secretary* shall in accordance with the *Governance and Structure By-law* provide the *applicant* with a list of at least three names of members of the *dispute resolution panel* available to determine the amount of any compensation payable to the *applicant*. Where the *applicant* fails to select an *arbitrator* within ten *business days* of receipt of such list, subject to section 2.7.1A, the *secretary* shall, in accordance with the *Governance and Structure By-law*, appoint one member of the *dispute resolution panel* to be the *arbitrator* in respect of the application and shall by written notice so advise the *applicant*. The *arbitrator* shall be deemed to have been appointed as of the date of such notice.

2.7.1E In the case of an application referred to in section 2.7.1D:

2.7.1E.1 sections 2.7.2, 2.7.8, 2.7.9, 2.7.10 and 2.7.32 shall not apply; and

2.7.1E.2 all other sections of this section 2.7 shall be read:

a. without regard to references to a *respondent*; and

b. by replacing all references to the word "party" or "parties" with the word "*applicant*".

2.7.2 The parties shall make good faith efforts to agree on the appointment of one of the members named on the list referred to in section 2.7.1 as the arbitrator to hear the dispute. Where the parties so agree, they shall by written notice so advise the *secretary*. Such member shall be the *arbitrator* for purposes of the resolution of the dispute and shall be deemed to have been appointed as of the date of such notice.

2.7.3 [Intentionally left blank]

2.7.4 [Intentionally left blank]

2.7.5 Where the parties to a dispute have failed to select an *arbitrator* within ten *business days* of receipt of the list referred to in section 2.7.1, or advise the *secretary* in accordance with section 2.7.1A, the *secretary* shall, in accordance with the *Governance and Structure By-law*, appoint one member of the *dispute resolution panel* to be the *arbitrator* in respect of the dispute and shall by written notice so advise the parties. The *arbitrator* shall be deemed to have been appointed as of the date of such notice.

2.7.6 An *arbitrator* shall be independent of the parties and shall act impartially. An *arbitrator* who is or becomes aware of circumstances that may give rise to a reasonable apprehension of bias shall promptly disclose them to the *secretary* and the parties.

2.7.7 An *applicant* shall, within thirty days of the appointment of the *arbitrator*, serve on any *respondent*, and file with the *arbitrator*, a written statement containing its submissions on each issue in dispute. At the same time, the *applicant* shall serve and file a list of all documents which it intends to file at the arbitration, copies of all such documents, and a list of witnesses intended to be called or to provide written evidence-in-chief at the hearing of the arbitration together with a concise written summary of the anticipated evidence of each witness. The *applicant* must indicate if it will be represented by legal counsel or some other representative and provide such person's name and address for service.

2.7.8 A *respondent* shall, within thirty days of the date of receipt of the *applicant's* materials referred to in section 2.7.7, serve on an *applicant* and on any other *respondent*, and file with the *arbitrator*, a written statement containing its submissions on each issue in dispute. At the same time, the *respondent* shall serve and file a list of all documents which it intends to file at the arbitration, copies of all such documents, and a list of witnesses intended to be called or to provide written evidence-in-chief at the hearing of the arbitration together with a concise written summary of the anticipated evidence of each witness. A *respondent* must indicate if it will be represented by legal counsel or some other representative and provide such person's name and address for service.

2.7.9 The *applicant* may, within ten days of receipt of the *respondent's* materials referred to in section 2.7.8, serve and file written reply submissions.

2.7.10 Where a *respondent* has made a counterclaim or a crossclaim in his or her *response*, the *respondent* shall, for purposes of the application of sections 2.7.7 to 2.7.9 and, where appropriate, of section 2.7.19, be treated as an *applicant* and the person against whom the counterclaim or the crossclaim has been made shall be treated as a *respondent* in respect of the counterclaim or crossclaim.

2.7.11 The *arbitrator* shall fix a date, time and place for the hearing following:

2.7.11.1 in the case of an application referred to in section 2.7.1B, the filing of the *applicant's* materials referred to in section 2.7.7; and

2.7.11.2 in all other cases, the service and filing of the *respondent's* materials referred to in section 2.7.8 or, where applicable, the materials of a *respondent* to the counterclaim or crossclaim referred to in section 2.7.10, which date shall be no more than sixty days from the date of the service and filing referred to in section 2.7.8 or, where applicable, of the service and filing referred to in section 2.7.10, whichever is the later, or such later date as may be agreed by each party to the arbitration. The *arbitrator* shall file with the *secretary* a notice of the date, time and place so fixed.

2.7.12 A *market participant* who might be directly affected by the award of the *arbitrator* in a dispute referred to in section 2.2.1 or 2.2.2.1 and, in the case of an application referred to in section 2.7.1D or of a dispute referred to in section 2.2.2.1, the *IESO*, may apply to the *arbitrator*, on notice to the parties, no less than five *business days* prior to the date of the hearing, for leave to intervene at the hearing. Parties may make submissions on the application for leave to intervene. The *arbitrator* may, in his or her sole discretion, grant leave to intervene to any *market participant* who demonstrates that it has an interest in the subject matter of the arbitration and may be directly affected by the decision in

the arbitration, on such terms and subject to such rights of participation as the *arbitrator* considers reasonable.

2.7.13 The procedures governing the arbitration shall be determined by the *arbitrator*, except as provided for under the market rules and by sections 19 to 22, 25 (other than 25(3) to 25(5)) to 33, 36, 36 and 40 to 44 of the *Arbitration Act, 1991*.

2.7.13.1 The *arbitrator* shall dismiss the *notice of dispute* and take no further action with respect to the *notice of dispute* if the *notice of dispute* was served outside of the timelines set forth in section 2.5.1A.

2.7.14 Nothing in writing shall be accepted in evidence at the hearing nor any witness be permitted to give evidence at the hearing, in both cases by or on behalf of an *applicant* or a *respondent*, except with leave of the *arbitrator*, unless the party has complied with the requirements set forth in section 2.7.7 or 2.7.8, as the case may be.

2.7.15 Any party to a dispute may apply to the *arbitrator* for, and the *arbitrator* may order, such further and other production as the *arbitrator* sees fit, provided that the *arbitrator* may not order the production by the *market surveillance panel* or the *market assessment unit* of *confidential information* which relates to a person who is not a party to the dispute. Evidence may be admitted by the *arbitrator* even if not admissible as evidence in a court of law.

2.7.16 The *arbitrator* may, with the consent of all parties, request an agent, employee, officer or director of the *IESO*, or a member of a panel established by the *IESO*, to provide him or her with any information or documentation which is not *confidential information* and which the *arbitrator* considers relevant to the conduct of the arbitration, and the *arbitrator* shall provide any such information or documentation to the parties in advance of the hearing at which such information or documentation is to be considered.

2.7.17 The *arbitrator* may, with the consent of the parties, request an agent, employee, officer or director of the *IESO*, or a member of a panel established by the *IESO*, to provide him or her with any information or documentation pertaining to a party which is *confidential information* and which the *arbitrator* considers relevant to the conduct of the arbitration. Subject to section 2.8.1, the *arbitrator* shall provide any such information or documentation to the parties in advance of the hearing at which such information or documentation is to be considered.

2.7.18 Whenever he or she considers necessary, the *arbitrator* may, upon such conditions as to confidentiality as the *arbitrator* determines appropriate and upon notice to the parties, obtain expert advice concerning technical aspects of the dispute. Arrangements for obtaining such advice shall be made by the *arbitrator*

or a party, as the *arbitrator* shall determine, provided that where such arrangements are made by the *arbitrator*, the *arbitrator* shall provide to the parties advance notice of the identity of the expert advisor.

2.7.19 At the hearing, the *applicant* shall provide its case in chief, followed by the *respondent* in response, and then the *applicant* in reply.

2.7.20 Witnesses shall be examined under oath or affirmation and shall be made available for cross-examination. Nothing in this section 2.7.20 shall preclude the *arbitrator* from dispensing with the oral examination-in-chief of a witness provided that a written statement of the witness's evidence is provided in such form as the *arbitrator* determines appropriate.

2.7.21 Subject to section 2.8.1, the arbitration shall be open to the public and all documents filed will form part of the public record of the proceedings.

2.7.22 The *arbitrator* shall deliver his or her award in writing, with reasons, within 30 days of completion of the hearing or within such longer period as may be agreed by each party to the dispute.

2.7.23 The *arbitrator* shall file a copy of his or her award with the *secretary*.

2.7.24 Where, in the case of a dispute referred to in section 2.2.1.1 or 2.2.1.1A, the *arbitrator* concludes that a *market participant* has violated a provision of the *market rules*, the *arbitrator* may in his or her award impose such financial penalties, assess such damages or make such further and other orders or directions as the *arbitrator* considers just and reasonable, provided that:

2.7.24.1 no financial penalty shall be imposed on a *market participant* unless the *arbitrator* determines that the breach of the *market rules* could have been avoided by the exercise of due diligence by the *market participant* or that the *market participant* acted intentionally; and

2.7.24.2 in fixing the amount of the penalty, the *arbitrator* shall have regard to the criteria set forth in section 6.6.7.

An award of the *arbitrator* under this section shall be deemed to be a decision or order of the *IESO* for purposes of the *market rules* and the application of the appeal provisions of section 36 of the *Electricity Act, 1998*.

2.7.25 Where, in the case of a dispute referred to in section 2.2.1.1 the *arbitrator* concludes that the *IESO* has violated, misinterpreted or misapplied a *market rule*, the *arbitrator* may, subject to section 13 of Chapter 1 and to any other provision of these *market rules* pertaining specifically to liability, assess such damages or

make such further and other orders or directions as the *arbitrator* considers just and reasonable. Without limiting the generality of the foregoing, where the *arbitrator* determines that the breach, misinterpretation or misapplication of a *market rule* by the *IESO* was intentional or could have been avoided by the exercise of due diligence by the *IESO*, the *arbitrator* shall direct the *IESO* to comply with the *market rules* or to interpret or apply the *market rules* in a particular manner. Any such direction may be included in the summary referred to in section 2.9.2.4.

2.7.25A Subject to section 13 of Chapter 1 and to any other provision of these *market rules* pertaining specifically to liability, the *arbitrator* may, in the case of a dispute referred to in section 2.2.1.2, 2.2.1.4 or 2.2.1.5, in addition to the orders referred to in section 2.7.26, 2.7.27 or 2.7.29, as the case may be, assess such damages or make such further and other orders or directions as the *arbitrator* considers just and reasonable.

2.7.26 Where a dispute referred to in section 2.2.1.1 relates to the terms and conditions upon which the *IESO* has authorized a person to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid*, the *arbitrator* may confirm the order of the *IESO* or set aside the order of the *IESO* and order the *IESO* to authorize the person to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid* on such other terms and conditions, if any, which the *arbitrator* determines are just and reasonable. An award of the *arbitrator* under this section 2.7.26 may include the direction to the *IESO* referred to in section 2.7.25 and shall be deemed to be a decision or order of the *IESO* for purposes of the *market rules* and the application of the appeal provisions of section 36 of the *Electricity Act, 1998*.

2.7.27 The *arbitrator* may:

2.7.27.1 in the case of a dispute referred to in section 2.2.1.2, confirm the order of the *IESO* or set aside the order of the *IESO* and order the *IESO* to authorize the person to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid*, on such terms and conditions, if any, which the *arbitrator* determines are just and reasonable;

2.7.27.2 in the case of a dispute referred to in section 2.2.1.5, and subject to section 2.7.29B, make such orders or directions as the *arbitrator* considers just and reasonable, and an award of the *arbitrator* under this section 2.7.27 may include the direction to the *IESO* referred to in section 2.7.25 and shall be deemed to be a decision or order of the

IESO for purposes of the *market rules* and the application of the appeal provisions of section 36 of the *Electricity Act, 1998*.

2.7.27A Notwithstanding section 2.7.27, in regards to those matters specified in section 2.5.1B, an arbitrator shall not order the *IESO* to take any action or make any adjustment in regards to any settlement amount which was invoiced, or the *IESO* had the right or obligation to invoice, more than 24 months before the date on which the *market participant* served the *notice of dispute*. Notwithstanding the foregoing, where entitlement to a *settlement amount* is prescribed by *applicable law*, an arbitrator shall not order the IESO to take any action or make any adjustment in regards to such settlement amount beyond the limitation period, if any, provided pursuant to *applicable law*.

2.7.28 In the case of an application referred to in section 2.2.1.3, the *arbitrator* may determine that no compensation is payable to the *applicant* or may order the *IESO* to pay compensation to the *applicant* in such amount and within such time as may be fixed by the *arbitrator* in accordance with any applicable provisions of section 6.7.5 of Chapter 5.

2.7.29 In the case of a dispute referred to in section 2.2.1.4:

2.7.29.1 where the dispute relates to the *reviewable decision* referred to in section 2.1.2 of Chapter 6, the *arbitrator* may confirm the order of the *IESO* or set aside the order of the *IESO* and order the *IESO* to authorize the person to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid* in respect of the relevant *connection point* on such terms and conditions, if any, which the *arbitrator* determines are just and reasonable, and such award of the *arbitrator* may include the direction to the *IESO* referred to in section 2.7.25 and shall be deemed to be a decision or order of the *IESO* for purposes of the *market rules* and the application of the appeal provisions of section 36 of the *Electricity Act, 1998*;

2.7.29.2 where the dispute relates to the *reviewable decision* referred to in section 5.3.9 of Chapter 6, the *arbitrator* may confirm the order or decision of the *IESO* or set aside the order or decision of the *IESO* and order the *IESO* to reinstate the registration of the *metering service provider* on such terms and conditions, if any, which the *arbitrator* determines are just and reasonable and the award of the *arbitrator* may include the direction to the *IESO* referred to in section 2.7.25;

2.7.29.3 where the dispute relates to the *reviewable decision* referred to in section 5.1.12 of Chapter 6, the *arbitrator* may confirm the order or

decision of the *IESO* or set aside the order or decision of the *IESO* and order the *IESO* to register the person as a *metering service provider* on such terms and conditions, if any, which the *arbitrator* determines are just and reasonable, and such award of the *arbitrator* may include the direction to the *IESO* referred to in section 2.7.25; or

2.7.29.4 where the dispute relates to the *reviewable decision* referred to in section 4.4.3 or 6.1.5 of Chapter 6, the *arbitrator* may confirm the order or decision of the *IESO* or set aside the order or decision of the *IESO* and order the *IESO* to register the *metering installation* on such terms and conditions, if any, which the *arbitrator* determines are just and reasonable, and such award of the *arbitrator* may include the direction to the *IESO* referred to in section 2.7.25.

2.7.29A In the case of a dispute referred to in section 2.2.2.1, the *arbitrator* may:

2.7.29A.1 determine an alternative apportionment of the *energy* associated with *connection station service* and with site specific losses amongst all applicable *market participants*; and

2.7.29A.2 determine whether, and the extent to which, any such alternative apportionment should be applied, by means of payments amongst the applicable *market participants*, to any period prior to the date on which the *IESO* gives effect to the proportions filed pursuant to section 2.1A.6B of Chapter 9.

2.7.29B Subject to section 2.7.27A, in the case of a dispute referred to in section 6.10.1 of Chapter 9, the *arbitrator* may, in considering whether to order the *IESO* to adjust *settlement statements* of multiple *market participants*, take into account:

2.7.29B.1 the dollar amount that is the subject-matter of the dispute;

2.7.29B.2 the time elapsed since the event that is the subject-matter of the dispute took place; and

2.7.29B.3 the *IESO's* ability to perform such adjustments.

2.7.30 In the case of a dispute referred to in section 2.2.2.2, the *arbitrator* may make such award, including but not limited to an award of damages, as is just and reasonable in the circumstances.

2.7.31 [Intentionally left blank]

2.7.32 Subject to section 2.7.32A, the *arbitrator* may make such award as to costs as he or she determines just and reasonable provided that, except in exceptional cases:

2.7.32.1 where in the context of a dispute referred to in section 2.2.1 the award consists of damages for breach of the *market rules*, costs, including the *costs of the arbitration*, shall be awarded to the successful party;

2.7.32.2 where the award consists of the imposition of penalties on a *market participant*, costs, including the *costs of the arbitration*, shall be awarded to the *IESO*; and

2.7.32.3 where the award consists of the direction to the *IESO* to comply with the *market rules* or to interpret or apply a *market rule* in a particular manner pursuant to section 2.7.25, costs, including the *costs of the arbitration*, shall be awarded to the *market participant* seeking the direction.

2.7.32A Where an award relates to an application referred to in section 2.7.1D and:

2.7.32A.1 the award consists of a determination by the *arbitrator* that the *applicant* is not entitled to any compensation pursuant to section 6.7.5 of Chapter 5; or

2.7.32A.2 no award as to costs is made pursuant to section 2.7.32B,

the *applicant* shall be responsible for his or her own costs and legal expenses associated with his or her participation in the arbitration and, subject to any determination of the *arbitrator* pursuant to section 2.7.33, shall bear the *costs of the arbitration*.

2.7.32B Where an award relates to an application referred to in section 2.7.1D and the award consists of a determination by the *arbitrator* that the *applicant* is entitled to compensation pursuant to section 6.7.5 of Chapter 5, the *arbitrator* may determine that some or all of:

2.7.32B.1 the *applicant's* costs and legal expenses associated with his or her participation in the arbitration; and

2.7.32B.2 the applicant's share of the costs of the arbitration,

be recovered by the *applicant*. Where the *arbitrator* makes such an award as to costs, the amount of such recoverable costs shall be paid by the *IESO* and recovered by the *IESO* in the same manner as the compensation referred to in section 6.7.5 of Chapter 5.

2.7.33 A person who intervenes in an arbitration shall be responsible for his or her own costs and legal expenses associated with his or her participation in the arbitration. The *arbitrator* may, in appropriate circumstances, require that an intervenor bear a portion of the *costs of the arbitration*.

2.7.34 An award of the *arbitrator* shall be enforceable in the manner provided in the *Arbitration Act, 1991*.

2.7.35 Where, in the case of a dispute referred to in section 2.2.1, the award consists of the payment of monies to the *IESO* or to a *market participant*, such award shall be considered to create an obligation under the *market rules* to pay the amount stated in the award and such amount may, without prejudice to any other manner of recovery available at law, be recovered accordingly. Except as may otherwise be provided in the award, any monies payable pursuant to an award shall be payable within 30 days of the date of the award.

2.7.36 Failure to comply with an award of an *arbitrator* in respect of a dispute referred to in section 2.2.1 constitutes a breach of the *market rules*.

2.7.37 Upon completion of an arbitration, the *arbitrator* shall file the record of the arbitration proceedings with the *secretary*. Where such record contains *confidential information* in respect of which a claim for confidentiality has been confirmed by the *arbitrator* pursuant to section 2.8.1, the *confidential information*, together with the stenographic record of any in camera hearings relating thereto, shall be sealed in an envelope clearly marked "CONFIDENTIAL" or otherwise identified as confidential and protected from disclosure prior to filing with the *secretary*.

2.7.38 Upon completion of the arbitration, the *arbitrator* shall file with the *secretary* an invoice containing an itemized statement of the *costs of the arbitration*, together with copies of all bills and other supporting documentation relating thereto.

2.7.39 Upon receipt of the invoice referred to in section 2.7.38, the *secretary* shall submit a copy of the invoice to the *IESO* and the *IESO* shall submit an invoice to each of the parties to the arbitration and, where applicable, each intervenor, in respect of their respective shares of the *costs of the arbitration*. Each such person shall, within ten *business days* of receipt of such invoice, pay to the *IESO* the amount owing thereunder. Such invoice shall be considered to create an obligation under the *market rules* to pay the amount specified in the invoice and such amount may, without prejudice to any other manner of recovery available at law, be recovered accordingly.

2.7.40 Where an *arbitrator* dies, resigns, is removed or otherwise becomes incapable of acting as an *arbitrator* in respect of a dispute prior to completion of the

arbitration, a replacement shall, with the consent of all of the parties to the arbitration, be selected by the *secretary* from among the remaining members of the *dispute resolution panel* in accordance with the *Governance and Structure By-law*. In the absence of such consent, subject to section 2.7.1A, the *secretary* shall forthwith provide the parties with a revised list of at least three names of members of the *dispute resolution panel* available to fill the vacancy and the parties shall make good faith efforts to agree on the appointment of one of the members named in the list as the replacement *arbitrator*. Where the parties so agree, they shall so advise the *secretary*.

2.7.41 [Intentionally left blank]

2.7.42 Where the parties have failed to select a replacement *arbitrator* within ten *business days* of receipt of the list referred to in section 2.7.40, subject to section 2.7.1A, the *secretary* shall, in accordance with the *Governance and Structure By-law*, appoint one member of the *dispute resolution panel* to be the replacement *arbitrator* and shall by written notice so advise the parties.

2.7.43 With the consent of the parties to the arbitration, once the *arbitrator* has been replaced, the *arbitrator* may continue the arbitration. In the absence of such consent, the replacement *arbitrator* shall commence the arbitration anew.

2.8 Confidentiality

2.8.1 Any party may claim that a document, or information contained in a document, to be produced in the context of the arbitration of a dispute is *confidential information*. The party making such a claim shall provide to the *arbitrator* in writing the basis for its assertion. If the claim of confidentiality is confirmed by the *arbitrator*, having regard, where applicable, to the provisions of section 5, the *arbitrator* shall establish requirements for the protection of such document or information as may be necessary to protect the confidentiality and commercial value of such document or information, including requirements for disclosure of same only to counsel and/or other independent advisor who has filed an undertaking as to confidentiality satisfactory to the *arbitrator* and for in camera hearings at which only representatives of the disclosing party and such counsel and/or other independent advisor may be present.

2.8.2 Members of the *dispute resolution panel* shall enter into such confidentiality agreement as may be required by the *IESO Board*.

2.9 Record-Keeping and Publication

2.9.1 Subject to section 2.9.1A, the *secretary* shall maintain a record of all dispute resolution proceedings conducted under this section 2. Upon the completion of a given dispute resolution proceeding, the *secretary* shall transfer the record to the *IESO*, addressed to the Chair of the Board of Directors of the *IESO* for archiving. The Chair shall be responsible for ensuring that all measures are taken to prohibit access by any other person to any portion of such record which may be sealed and marked "CONFIDENTIAL" or otherwise identified as being confidential, except as may be required by *applicable law* or permitted by the provisions of section 5.

2.9.1A For the purposes of section 2.9.1, the record referred to therein shall not include any record pertaining to or arising from the mediation of a dispute other than:

2.9.1A.1 the name and address for service of the person appointed to act as the *mediator* in respect of the dispute;

2.9.1A.2 the agreement referred to in section 2.6.5;

2.9.1A.3 the settlement agreement referred to in section 2.6.12;

2.9.1A.4 the notice of termination of mediation referred to in section 2.6.13 or 2.6.16;

2.9.1A.5 the agreed statement of fact and/or issues referred to in section 2.6.13 or 2.6.16; and

2.9.1A.6 information and documentation pertaining to the *costs of the mediation*, including the invoice referred to in section 2.6.18.

2.9.2 The *secretary* shall arrange for *publication* by the *IESO* of the following:

2.9.2.1 the summaries referred to in sections 2.5.3C, 2.5.6 and 2.5.6C as may be applicable upon the appointment of the *arbitrator*;

2.9.2.2 notice of the appointment of an *arbitrator* and the address for service of the *arbitrator*;

2.9.2.3 notice of the date, time and place fixed for hearing pursuant to section 2.7.11; and

2.9.2.4 a summary of the award of an *arbitrator* filed pursuant to section 2.7.23, which may include the information required by section 2.7.25.

2.9.3 The *IESO* shall *publish* the fees payable to members of the *dispute resolution panel* involved in the resolution or the attempted resolution of a dispute pursuant to this section 2, as such fees may from time to time be fixed in accordance with the provisions of the *Governance and Structure By-law*.

2.10 Audit

2.10.1 The activities of the *dispute resolution panel* shall be audited in accordance with procedures adopted from time to time by the *IESO*.

3. Market Surveillance

3.1 [Intentionally left blank – section deleted]

3.2 Establishment and Staffing of Market Assessment Unit

3.2.1 A *market assessment unit* shall be established by the *IESO* to perform the functions given to it under the *market rules* and to support, in the manner agreed to by the *IESO* and the *OEB*, the *market surveillance panel.*

3.2.2 [Intentionally left blank – section deleted]

3.2.3 [Intentionally left blank – section deleted]

3.2.4 [Intentionally left blank – section deleted]

3.3 Market Monitoring Functions

3.3.1 The *market assessment unit* shall conduct such monitoring, evaluation, analysis and reporting activities in support of the work of the *market surveillance panel* as may be agreed between the *IESO* and the *OEB*.

3.3.1.1 [Intentionally left blank – section deleted]

3.3.1.2 [Intentionally left blank – section deleted]

3.3.1.3 [Intentionally left blank – section deleted]

3.3.1A Notwithstanding any other provision of Chapter 3, the *IESO* shall provide the *market surveillance panel* with such information as it may require from time to time.

3.3.2 [Intentionally left blank – section deleted]

3.3.2A [Intentionally left blank – section deleted]

3.3.3 [Intentionally left blank – section deleted]

3.3.3A [Intentionally left blank – section deleted]

3.3.4 [Intentionally left blank – section deleted]

3.3.5 [Intentionally left blank – section deleted]

3.3.5A *Market participants* shall provide the *market assessment unit* with the data identified in the detailed catalogue adopted and published by the *market surveillance panel* in accordance with the *OEB* by-laws.

3.3.6 [Intentionally left blank – section deleted]

3.3.7 [Intentionally left blank – section deleted]

3.3.8 [Intentionally left blank – section deleted]

3.3.8A [Intentionally left blank – section deleted]

3.3.8B [Intentionally left blank – section deleted]

3.3.9 [Intentionally left blank – section deleted]

3.3.10 [Intentionally left blank – section deleted]

3.3.10A [Intentionally left blank – section deleted]

3.3.11 [Intentionally left blank – section deleted]

3.3.12 [Intentionally left blank – section deleted]

3.3.13 [Intentionally left blank – section deleted]

3.4 [Intentionally left blank – section deleted]

3.5 [Intentionally left blank – section deleted]

3.6 [Intentionally left blank – section deleted]

3.7 [Intentionally left blank – section deleted]

3.8 Dispute Resolution and Other Relief

3.8.1 The dispute resolution procedures under section 2 shall not apply to the activities of the *market assessment unit* under this section 3.

3.8.2 Nothing in this section 3 shall prevent the *IESO* or any other person from asserting any rights they may have under any *applicable law* or under the *market rules*.

3.9 [Intentionally left blank – section deleted]

3.10 [Intentionally left blank – section deleted]

4. Rule Amendments

4.1 Introduction and Interpretation

4.1.1 This section 4 sets forth the procedures pursuant to which *amendments* to the *market rules* may be made by the *IESO* and embodies the mechanism for review of the *market rules* for purposes of the application of subsection 35(4) of the *Electricity Act, 1998*.

4.1.2 This section 4 must be read and construed subject to the *Governance and Structure By-law*.

4.2 Amendment Process Generally

4.2.1 Under section 32 of the *Electricity Act, 1998*, the *IESO Board* has the authority and responsibility to *amend* these *market rules*. The *technical panel* is authorized, through the *Governance and Structure By-law*, to support the *IESO Board* in the development and consideration of *amendments* to the *market rules*. The *urgent rule amendment committee* is authorized, through the *Governance and Structure*

By-law, to support the *IESO Board* in the development, consideration and making of *urgent rule amendments*.

4.2.2 In formulating *amendments* to the *market rules*, the *IESO Board*, the *technical panel* and the *urgent rule amendment committee* shall take into consideration the objects of the *IESO* as set forth in the *Electricity Act*, *1998*.

4.2.3 The *IESO Board* may review, from time to time, the work and proceedings of the *technical panel* and issue to the *technical panel* such directions as the *IESO Board* from time to time determines appropriate. Such directions may relate to one or more proceedings respecting particular proposed *amendments* to or reviews of the *market rules* or may be of more general application. For certainty, such directions may include termination of the consideration of a particular proposed *amendment* to, or review of, the *market rules*. The *technical panel* shall comply with such directions. In addition, nothing in this section 4 shall prohibit the *technical panel* from consulting with the *IESO Board* regarding the role the *technical panel* will play in reviewing a request for an *amendment* or review of the *market rules*.

4.2.4 A *market participant* or any other interested person may file a written submission (the "*amendment submission*") with the *IESO*, at such address as may be *published* by the *IESO* from time to time, to propose one or more *amendments* to the *market rules* or to identify any provision of the *market rules* in respect of which the *market participant* or the other interested person considers that an *amendment* or review may be necessary or desirable. The *amendment submission* shall include a statement of the reasons for which an *amendment* to or review of the *market rules* may be necessary or desirable.

4.2A Rule Amendments Initiated by the IESO Board

4.2A.1 The *IESO Board* may at any time determine on its own initiative or at the request of any person that an *amendment*, including a *minor amendment*, to or a review of a *market rule* may be necessary or desirable and shall *publish* and give notice of its intention to consider such *amendment* or review, together with a statement of the reason for which such *amendment* or review may be necessary or desirable:

4.2A.1.1 to all market participants;

4.2A.1.2 to the *technical panel*;

4.2A.1.3 where such *amendment* or review relates to or may affect any provision of section 2, to the *secretary* of the *dispute resolution panel*; and

4.2A.1.4 where such *amendment* or review relates to or may affect any provision of section 3, to the Chair of the *market surveillance panel*,

inviting such persons to make, within such reasonable period as shall be specified in the notice, written submissions to the *IESO Board* concerning the matter. The reasonable period shall not be less than 7 days.

4.2A.2 Sections 4.3.9 to 4.3.11 and 4.3.13 to 4.3.20 shall apply, with such modifications as the context may require, to consideration by the *IESO Board* of a proposed *amendment*, other than a *minor amendment* which shall be made in accordance with section 4.7, or review pursuant to this section 4.2A, it being understood that the references in those sections to the *technical panel* shall be considered references to the *IESO Board*, unless and to the extent that the *IESO Board* directs the *technical panel* to participate in the matter.

4.2A.3 Sections 4.7.1 to 4.7.6, other than sections 4.7.1.1 and 4.7.1.2, apply with such modifications as the context may require to consideration by the *IESO Board* of a *minor amendment* pursuant to this section 4.2A, it being understood that the references in those sections to the *technical panel* shall be considered references to the *IESO Board*, unless and to the extent that the *IESO Board* directs the *technical panel* to participate in the matter.

4.3 Requests for Review or Amendment of Market Rules

4.3.1 The provisions of this section 4.3 apply to requests made by the *IESO Board*, and *amendment submissions* made by a *market participants* or any other interested person for an *amendment* or review of the *market rules*, and do not apply:

4.3.1.1 except as expressly provided in section 4.4.3 or 4.2A.2, to proposed *amendments* to which sections 4.4 or 4.2A, respectively, apply;

4.3.1.2 to *urgent amendments* to the *market rules*, which shall be made in accordance with section 4.6; and

4.3.1.3 to *amendments* to the *market rules* which are required to be made or reconsidered further to an order of the *Ontario Energy Board* pursuant to the provisions of the *Electricity Act, 1998*, which shall be made in accordance with section 4.8.

4.3.2 Upon receipt of the *amendment submission,* the *technical panel* may request that the person submitting the *amendment submission* provide further particulars with respect to the *amendment submission*.

4.3.3 [Intentionally left blank]

4.3.4 [Intentionally left blank]

4.3.5 The *technical panel* shall report to the *IESO Board* and, where applicable, give notice to the *market participant* or other interested person who made an *amendment submission* as to whether the proposed *amendment* or the request for consideration of an *amendment* or review is, in the opinion of the *technical panel*:

4.3.5.1 of such a nature that consideration of the *amendment submission* is warranted and the extent of the consultation that the *technical panel* intends to take with *market participants* and other interested persons in the consideration of the *amendmen*t;

4.3.5.1A of such a nature that it raises only a *minor amendment*, in which case the *amendment submission* shall be dealt with in accordance with the provisions of section 4.7;

4.3.5.1B of such a nature that a clarification or interpretation of the applicable *market rule* is warranted, in which case the *amendment submission* shall be dealt with in accordance with the provisions of section 12 of Chapter 1; or

4.3.5.2 with reasons specified in the report and notice, of such a nature that no consideration of the *amendment submission* is warranted,

provided that the *technical panel* shall not make the determination referred to in section 4.3.5.2 where the request was made by the *IESO Board* unless the *IESO Board*, in its request, so permits.

4.3.6 The *technical panel* shall nonetheless further consider or not consider the *amendment submission*, as the case may be, if it is directed to do so by the *IESO Board.*

4.3.7 Where the *technical panel* decides or is required to further consider an *amendment submission* pursuant to section 4.3.5 or 4.3.6, the *IESO* shall *publish* and give notice to all *market participants* and to any person who made the *amendment submission,* of the particulars of the *amendment submission* and of any comments which the *technical panel* may wish to make in respect of the *amendment submission*. The notice and *publication* may, at the request of *technical panel*, invite *market participants* and other interested persons to make written submissions to the *technical panel* concerning the *amendment submission*, within such reasonable period as shall be determined by the *technical panel*, and as specified in the *publication* and notice. This reasonable period shall not be less than 7 days.

4.3.8 The written submissions referred to in section 4.3.7 must be filed with the *technical panel* within the time specified in the notice and *publication* and may indicate whether the *market participant* or the other interested person considers that a meeting is necessary or desirable in connection with the *amendment submission* and, if so, the reasons why such meeting is necessary or desirable.

4.3.9 The *technical panel* may at any time give notice, and invite *market participants* or other interested persons, to make such additional written submissions within such reasonable time as the *technical panel* determines appropriate.

4.3.10 The *technical panel* shall consider all written submissions received within the prescribed time pursuant to section 4.3.8 or 4.3.9 and may, where the *technical panel* considers it necessary or desirable, schedule and hold meetings in accordance with section 4.3.11.

4.3.10A In its consideration of an *amendment submission*, the *technical panel* shall also consider any unsolicited written submissions that are received in time for the *technical panel* meeting at which the applicable *amendment submission* is being considered.

4.3.11 The *technical panel* shall advise the *IESO Board* of the date, time and place scheduled for any meeting referred to in section 4.3.10 and the *IESO* shall, no less than seven days prior to the date fixed for a meeting, *publish* and give notice of same to *market participants* and to any person who filed written submissions pursuant to section 4.3.8 or 4.3.9. Any *market participant* and any other interested person may attend and, at the discretion of the *technical panel,* participate in any such meetings.

4.3.12 Where the *amendment submission* relates to or may affect:

4.3.12.1 any provision of section 2, the *technical panel* shall, prior to conducting any meetings pursuant to section 4.3.11 or, in the absence of such meetings, prior to voting on the matter, consult with the *secretary* of the *dispute resolution panel* with respect to the matter; and

4.3.12.2 any provision of section 3, the *technical panel* shall, prior to conducting any meetings pursuant to section 4.3.11 or, in the absence of such meetings, prior to voting on the matter, consult with the Chair of the *market surveillance panel* with respect to the matter.

4.3.13 The *technical panel* shall, as soon as reasonably practicable following any meetings and consultations which may have been held pursuant to sections 4.3.11 and 4.3.12, or any other consultations that the *technical panel* decides are

appropriate, convene on one or more occasions as may be necessary to consider and vote on the *amendment* resulting from an *amendment submission*. Prior to the *technical panel* voting on an *amendment*, the *IESO* shall, at the request of *technical panel*, *publish,* and give notice to all *market participants* and to any person who made the *amendment submission* or written submission to which the proposed *amendment* relates, of the proposed *amendment* that will be the subject of the *technical panel's* vote. The notice and *publication* shall, at the request of the *technical panel*, invite *market participants* and other interested persons to make written submission to the *technical panel* concerning the subject *amendment*, within such reasonable period as shall be determined by the *technical panel* and specified in the notice and *publication*. This reasonable period shall not be less than 7 days.

4.3.14 Following the conclusion of the deliberations referred to in section 4.3.13, the *technical panel* shall submit a written report to the *IESO Board* setting out:

4.3.14.1 the recommendations of the *technical panel* and the reasons for its recommendations;

4.3.14.2 where the recommendations of the *technical panel* include a proposal to *amend* the *market rules*, a copy of the proposed text of the amendment and a summary of any objections to the *amendment submission* which may have been contained in the written submissions referred to in section 4.3.8, 4.3.9, 4.3.10A or 4.3.13 or brought to the attention of the *technical panel* during any meetings held pursuant to section 4.3.11 or otherwise;

4.3.14.3 a summary of the procedure followed by the *technical panel* in considering the matter;

4.3.14.4 a summary of the views of the *secretary* of the *dispute resolution panel* or the Chair of the *market surveillance panel*, as the case may be, provided during the consultations referred to in section 4.3.12;

4.3.14.5 a record of the vote of each member of the *technical panel* in respect of each of the recommendations made in the report;

4.3.14.6 a summary of any objections raised by any member of the *technical panel* to the recommendations, if such objecting member so requests; and

4.3.14.7 a statement of the objects of the *IESO* considered by the *technical panel* in formulating the *amendment* as required by section 4.2.2.

4.3.15 The *IESO* shall *publish* the recommendations contained in the report of the *technical panel* referred to in section 4.3.14 and give notice thereof to all *market participants* and to any person who made an *amendment submission* or written submission to which the recommendations relate. In this notice and *publication*, the *IESO* shall, at the request of the *technical panel*, invite *market participants* and other interested persons to make written submissions to the *IESO Board* concerning the subject *amendment*, within seven *business days* of the date of giving of notice, objecting to the *technical panel's* recommendation and setting forth the reasons for the objection. At the request of the *IESO Board*, the *technical panel* shall provide to the *IESO Board* copies of all written submissions received pursuant to section 4.3.8, 4.3.9, 4.3.10A or 4.3.13, together with particulars of any written submissions which were made before the *technical panel* during the course of any meetings that may have been held pursuant to section 4.3.11.

4.3.16 [Intentionally left blank]

4.3.17 As soon as reasonably practicable following receipt of the report of the *technical panel* referred to in section 4.3.14 or, where written submissions have been requested pursuant to section 4.3.15, following the expiry of the deadline for written submissions referred to in that section, the *IESO Board* shall convene on one or more occasions as may be necessary to consider the report of the *technical panel*, together with any written submissions received pursuant to section 4.3.15, and shall vote on the matter in accordance with the provisions of the *Governance and Structure By-law*.

4.3.18 Where the *IESO Board* decides against the adoption of an *amendment* to the *market rules*, the *IESO* shall *publish* such decision and shall give notice of the decision to all *market participants* and to any person who made an *amendment submission* or written submission to which the decision relates. Where the *IESO Board* decides in favour of the adoption of the *amendment* to the *market rules,* either as recommended by the *technical panel* or with changes made by the *IESO Board* in its consideration of the *amendment*, the *IESO* shall publish such decision, together with a copy of the *amendment*, in accordance with the provisions of the *Governance and Structure By-law* and the *Electricity Act, 1998*, and shall give notice of the decision to all *market participants* the *Ontario Energy Board* and to any person who made the *amendment submission* or written submission to which the decision relates.

4.3.19 Where, in accordance with the *Governance and Structure By-law*, the *IESO Board* refers a recommendation contained in a report of the *technical panel* either back to the *technical panel* for further consideration and vote, or to any other person that the *IESO Board* deems appropriate, the *IESO Board* shall so advise the *technical panel*, with reasons, and shall *publish* such decision and give notice

of the decision to all *market participants* and to any person who filed an *amendment submission* or written submission to which the decision relates. The *technical panel* shall, as soon as reasonably practicable following receipt of the decision of the *IESO Board*, convene to reconsider its recommendation. The *technical panel* may enter into such further consultations with such persons, and conduct such meetings, as it determines appropriate for purposes of its reconsideration.

4.3.20 Sections 4.3.14 to 4.3.18 shall apply, with such modifications as may be required by the context, to the reconsideration of a recommendation pursuant to section 4.3.19.

4.4 Rule Amendments Initiated by the Technical Panel

4.4.1 The provisions of this section 4.4 do not apply to *minor amendments* proposed by the *technical panel*, which shall be made in accordance with section 4.7.

4.4.2 Where the *technical panel* on its own initiative determines at any time that an *amendment* to or a review of a *market rule* may be necessary or desirable, it shall submit a report of its intention to consider such *amendment* or review to the *IESO Board*, together with the reasons for its determination.

4.4.3 Sections 4.3.7 to 4.3.20 shall apply, with such modifications as the context may require, to consideration of the matter raised in the *review notice*, it being understood that the reference in those sections to an *amendment submission* shall be a reference to the *review notice*.

4.5 [Intentionally left blank]

4.5.1 [Intentionally left blank]

4.5.2 [Intentionally left blank]

4.5.3 [Intentionally left blank]

4.6 Urgent Amendments

4.6.1 *Urgent amendments* to the *market rules* shall be made by the *IESO Board* or the *urgent rule amendment committee*, if so authorized by the *IESO Board* pursuant to the *Governance and Structure By-law*, following such consultations with such persons as the *urgent rule amendment committee* or the *IESO Board*, as the case may be, considers appropriate.

4.6.2 Where an *urgent amendment* is made pursuant to section 4.6.1 by the *urgent rule amendment committee*, such *amendment* shall forthwith be reported to the *IESO Board*.

4.6.3 The *IESO Board* shall, in accordance with the provisions of the *Governance and Structure By-law*, convene on one or more occasions as may be necessary to consider the report and vote to either:

4.6.3.1 confirm the *urgent amendment*, in the form made by the *urgent rule amendment committee* or in such form as the *IESO Board* deems appropriate; or

4.6.3.2 reject the *urgent amendment* and stay the implementation thereof.

4.6.4 Where an *urgent amendment* is made by the *IESO Board* or the *urgent rule amendment committee* pursuant to section 4.6.1, the *IESO* shall forthwith *publish* and give notice, including the effective date and time, of such *urgent amendment* and shall give notice thereof to all *market participants*.

4.6.5 Where an *urgent amendment* is confirmed by the *IESO Board* pursuant to section 4.6.3.1 in a form other than that made by the *urgent rule amendment committee*, the *IESO* shall forthwith *publish* and give notice, including the effective date and time, of such *urgent amendment* and shall give notice thereof to all *market participants*.

4.6.6 Where the *IESO Board* rejects and stays the implementation of an *urgent amendment* pursuant to section 4.6.3.2, the *IESO* shall forthwith *publish* and give notice, including the effective date and time, of its decision to all *market participants*.

4.7 Minor Amendments

4.7.1 If the *technical panel* considers that it is necessary or desirable to make a *minor amendment* to the *market rules*, either on its own initiative or upon receipt of an *amendment submission,* the *technical panel* shall hold such consultations with such persons, or ask for written submissions only from such *market participants*, if any, as the *technical panel* considers appropriate and shall:

4.7.1.1 where such *minor amendment* relates to or may affect any provision of section 2, consult with the *secretary* of the *dispute resolution panel*; or

4.7.1.2 where such *minor amendment* relates to or may affect any provision of section 3, consult with the Chair of the *market surveillance panel*,

and each of the *secretary* and the Chair shall consult such members of their respective panels as they determine appropriate prior to consulting with the *technical panel.*

4.7.2 After holding any consultations or receiving any written submissions pursuant to section 4.7.1, the *technical panel* shall convene on one or more occasions as may be necessary to consider and vote on the matter and shall thereafter submit a written report to the *IESO Board* containing the information set forth in section 4.3.14.

4.7.3 [Intentionally left blank]

4.7.4 [Intentionally left blank]

4.7.5 As soon as reasonably practicable following the receipt of the report of the *technical panel* referred to in section 4.7.2 the *IESO Board* shall convene on one or more occasions as may be necessary to consider and vote on the *minor amendment* in accordance with the *Governance and Structure By-law* and shall:

4.7.5.1 approve the *minor amendment* as submitted by the *technical panel* or with any changes that the *IESO Board* determines are appropriate; or

4.7.5.1A reject the *minor amendment*, or

4.7.5.2 refer the matter back to the *technical panel.*

4.7.5A The *IESO* shall *publish* the *IESO Board* decision made pursuant to section 4.7.5, together with a copy of the *amendment*, in accordance with the provisions of the *Governance and Structure By-law* and the *Electricity Act, 1998*, and shall give notice of the decision to all *market participants,* the *Ontario Energy Board* and to any person who made the *amendment submission* or made a written submission to which the decision relates.

4.7.6 Sections 4.3.7 to 4.3.20 shall, unless and to the extent that the *IESO Board* directs otherwise, apply with such modifications as the context may require to the further consideration by the *technical panel* of a matter referred to it under section 4.7.5.2.

4.8 Amendments Subject to Order of the Ontario Energy Board

4.8.1 Upon receipt of an order of the *Ontario Energy Board* made pursuant to the provisions of the *Electricity Act, 1998* from which no appeal, review or petition to

the Lieutenant Governor in Council can or has been taken, the *IESO Board* shall either:

4.8.1.1 refer the matter, including consideration of any consequential *amendments* arising from the matter, to the *technical panel*, and the provisions of sections 4.3.7 to 4.3.20 shall, unless and to the extent that the *IESO Board* directs otherwise, apply with such modifications as the context may require to the reconsideration of the *amendment* to the *market rules* which is the subject of the order; or

4.8.1.2 following such consultations as the *IESO Board* considers appropriate, make an *amendment* to the *market rules* including any consequential *amendments* arising from the matter. The *IESO* shall *publish* the *amendment* and shall give notice of the *amendment* to all *market participants* and the *Ontario Energy Board*.

4.8.2 Upon receipt of an order of the *Ontario Energy Board* made pursuant to subsection 35(6) or 38(4) of the *Electricity Act, 1998* from which no appeal, review or petition to the Lieutenant Governor in Council can or has been taken, the *IESO Board* shall make an *amendment* to the *market rules* in the manner and within the time specified by the *Ontario Energy Board* in its order, including any consequential *amendments* arising from the matter, following such consultations as the *IESO Board* considers appropriate. The *IESO* shall *publish* the *amendment* and shall give notice of the *amendment* to all *market participants* and the *Ontario Energy Board*.

4.9 Experts and Other Assistance

4.9.1 The *technical panel* may, subject to the *Governance and Structure By-law* of the *IESO* and to budgetary approval of the Chief Executive Officer of the *IESO,* hire such consulting assistance and seek such expert external advice as may be necessary or desirable for the purpose of the fulfillment of its responsibilities under this section 4. Where the Chief Executive Officer of the *IESO* does not approve such request, the *technical panel* may appeal such decision to the Chair of the *IESO Board.*

4.9.1A Consultants and expert external advisors hired pursuant to section 4.9.1 shall enter into such confidentiality agreement as may be required by the Chair of the *technical panel.*

4.9.2 In carrying out any of its responsibilities under this section 4, the *technical panel* may, through the Chief Executive Officer of the *IESO*, solicit the assistance of

any director, officer or employee of the *IESO* and may use the facilities of the *IESO*.

4.9.3 Where the *technical panel* at any time considers it necessary or desirable to do so, it may establish working groups to assist it in the fulfillment of its responsibilities under this section 4, which working groups shall operate in accordance with such terms and conditions, including as to the scope of their work and as to participation in such working groups, as the *technical panel* may reasonably determine to be appropriate. The *technical panel* shall notify the *IESO Board* of its intention to establish a working group and the *IESO* shall *publish* and give notice to all *market participants,* the person who made the *amendment submission* and any other interested party that made written submissions in respect of the proposed *amendment* to which the working group relates of such intention.

4.9.4 The *IESO Board* may, at any time in fulfilling its responsibilities under this section 4, including but not limited to for the purposes of section 4.8.2, call upon the assistance of the *technical panel*.

4.10 [Intentionally left blank]

4.10.1 [Intentionally left blank]

4.10.2 [Intentionally left blank]

4.10.3 [Intentionally left blank]

4.11 [Intentionally left blank]

4.11.1 [Intentionally left blank]

4.12 Audit

4.12.1 The activities of the *technical panel* shall be audited in accordance with procedures adopted from time to time by the *IESO*.

5. Accessibility and Confidentiality of Information

5.1 Accessibility

5.1.1 Subject to section 5.7.1, all persons shall have an equal opportunity for open and non-discriminatory access to all information, other than *confidential information*, required by the *market rules* to be made available to *market participants*, the *IESO* or other persons.

5.1.2 Subject to section 5.7.1, all information, other than *confidential information*, required by the *market rules* to be made available to *market participants*, the *IESO* or other persons shall be *published* or otherwise made available in the manner and within the time prescribed in the *market rules*. Where no time is specified in respect of the provision of a particular piece of information, such information shall be made available within a reasonable time.

5.1.3 All *market participants* shall have an equal opportunity for access to information, other than *confidential information*, made available pursuant to the *market rules*.

5.1.3A Notwithstanding sections 5.1.1, 5.1.2, 5.1.3 or any other sections of the *market rules*, the *IESO* may withhold information that if disclosed may, in the reasonable opinion of the *IESO*, pose a security threat to the *reliable* operations of the *integrated power system*, the *IESO-administered markets*, or those of neighbouring jurisdictions.

5.1.4 In this section 5:

5.1.4.1 a reference to the *IESO* shall include a reference to a panel established by the *IESO;* and

5.1.4.2 a reference to information shall mean information however recorded, whether in printed form, on film, by electronic means or otherwise.

5.2 Confidentiality

5.2.1 Each *market participant* and the *IESO* shall keep confidential any *confidential information* which comes into the possession or control of that *market participant* or the *IESO* or of which the *market participant* or the *IESO* becomes aware.

5.2.2 No *market participant* or the *IESO* shall:

5.2.2.1 disclose *confidential information* to any person except as permitted by the *market rules*;

5.2.2.2 permit access to *confidential information* by any person not authorized to have such access pursuant to the *market rules*; or

5.2.2.3 use or reproduce *confidential information* for a purpose other than the purpose for which it was disclosed or another purpose contemplated by the *market rules*.

5.2.3 Each *market participant* and the *IESO* shall:

5.2.3.1 prevent access to *confidential information* which is in its possession or control by any person not authorized to have such access pursuant to the *market rules*, including by appropriate means of destruction or disposal in cases where the *confidential information* is not required or is at the relevant time no longer required to be retained by it pursuant to the *market rules*; and

5.2.3.2 ensure that any person to whom it discloses *confidential information* observes the provisions of this section 5.2 in relation to that *confidential information*.

5.2.4 Each *market participant* and the *IESO* shall, promptly upon becoming aware of a breach or a threatened breach of the provisions of this section 5 with respect to an item of *confidential information*:

5.2.4.1 so notify any person to whom the *confidential information* relates or by whom it was provided;

5.2.4.1A if a *market participant*, so notify the *IESO*; and

5.2.4.2 take such reasonable steps as may be required to prevent or assist in the prevention of, as the case may be, the unauthorized disclosure, access to, use or reproduction of *confidential information* that may result from such breach or threatened breach.

5.2.5 Each *market participant* shall maintain internal measures relating to the protection of *confidential information* that enable the *market participant* to comply and monitor compliance with its obligations under this section 5.

5.2.6 The *IESO* shall maintain internal measures, including measures referred to in section 5.7.2, relating to the protection of *confidential information* that enable the *IESO* to comply and monitor compliance with its obligations under this section 5.

5.3 Exceptions

5.3.1 Unless prohibited by *applicable law* or by the provisions of these *market rules* other than this section 5, nothing in sections 5.2, 5.4 or section 5.5.1A of Chapter 5 shall prevent:

5.3.1.1 the disclosure, use or reproduction of information if the information is, at the time of disclosure, generally and publicly available other than as a result of a breach of confidence by the *market participant* or the *IESO* who wishes to disclose, use or reproduce the information or by any person to whom the *market participant* or the *IESO* has disclosed the information;

5.3.1.2 the disclosure of confidential information by a market participant or the IESO to:

a. a director, officer or employee of the *market participant* or of the *IESO* where such person requires the *confidential information* for the due performance of that person's duties and responsibilities and, in the case of the *IESO* for information that is classified highly confidential pursuant to section 5.4.2.6, where the person has the required security clearance assigned by the *IESO*; or

b. a legal or other professional advisor, auditor or other consultant of the *market participant* or of the *IESO* where such persons require the information for purposes of the *market rules* or of an agreement entered into pursuant to the *market rules* or for the purpose of advising the *market participant* or the *IESO* in relation thereto;

5.3.1.3 the disclosure, use or reproduction of *confidential information*:

a. by the *market participant* or person that provided the *confidential information* pursuant to the *market rules*;

b. with the consent of the *market participant* or person that provided the *confidential information* pursuant to the *market rules*; or

c. in the case of *settlement* data, *metering data* or data contained in the *metering registry*, by or with the consent of the *market participant* to whom such data relates;

5.3.1.4 the disclosure, use or reproduction of *confidential information* to the extent required by *applicable law* or by a lawful requirement of:

a. any government or governmental body, regulatory body, authority or agency having jurisdiction over a *market participant* or the *IESO* or an *affiliate* of a *market participant* or of the *IESO*; or

b. any stock exchange having jurisdiction over a *market participant*, the *IESO* or an *affiliate* of a *market participant* or the *IESO*;

5.3.1.5 except as otherwise provided in section 2, the disclosure, use or reproduction of *confidential information* if required in connection with legal proceedings, mediation, arbitration, expert determination or other dispute resolution mechanism relating to the *market rules* or to an agreement entered into pursuant to the *market rules* or for the purpose of advising a person in relation thereto;

5.3.1.5A if required by the *IESO Board* or a committee established by the *IESO Board*, the disclosure, use or reproduction of *confidential information* if required in connection with the issuance of *suspension*, *termination* or *disconnection orders* in respect of one or more *market participants* the revocation of the registration in respect of one or more *metering service providers* and any show cause hearings in respect thereof under section 5.3 of chapter 6 or section 6.2A;

5.3.1.6 the disclosure of *confidential information* if required to ensure the safety of any person, prevent the damage of equipment, prevent the violation of any *applicable law*, or to maintain the *reliability* of the *IESO-controlled grid*;

5.3.1.7 the disclosure, use or reproduction of *confidential information* as an unidentifiable component of an aggregate sum;

5.3.1.8 the disclosure by the *IESO* of *confidential information* to a *transmitter* for the purposes of:

a. the safe and reliable management, operation and maintenance of its *transmission system* to the extent that *confidential information* is required pursuant to the terms of the *operating agreement*; or

b. the verification or reconciliation of the collection and administration of any applicable *transmission services charges*;

5.3.1.9 the disclosure by the IESO of confidential information to a market participant:

a. during an *emergency* or where the *IESO-controlled grid* is in an *emergency operating state* or a *high-risk operating state*; or

b. where an *emergency*, an *emergency operating state* or a *high-risk operating state* is anticipated by the *IESO*;

to the extent that such disclosure would, in the *IESO's* opinion:

c. assist the *market participant* in responding to the conditions referred to in sections 5.3.1.9(a) and 5.3.1.9(b); or

d. assist the *IESO* in restoring the *IESO-controlled grid* to a *normal operating state*;

5.3.1.10 disclosure by the IESO of confidential information to a standards authority, a control area operator, a security coordinator or an interconnected transmitter;

5.3.1.11 disclosure by the IESO of confidential information to the market surveillance panel;

5.3.1.12 subject to sections 5.3.7 and 5.3.8, disclosure by the *IESO* of *confidential information* to a *market monitoring unit* relating to an investigation regarding conduct or activities which may have an adverse impact on market efficiency or effective competition; or

5.3.1.13 subject to section 5.3.10 and at the sole discretion of the *IESO*, disclosure by the *IESO* of *confidential information* in the form of a *basecase,* for the purposes of conducting reliability based power system studies directly to, or to a consultant of, a *market participant*, a *connection applicant,* or to a person planning to construct or modify a *facility*.

5.3.2 Prior to making any disclosure pursuant to section 5.3.1.2(b), the person wishing to disclose the information shall inform the proposed recipient of the confidential nature of the *confidential information* to be disclosed and shall use all reasonable endeavours, including but not limited to the execution of an appropriate confidentiality agreement, to ensure that the recipient keeps the *confidential information* confidential in accordance with the provisions of section 5.2 and does not use the *confidential information* for any purpose other than that permitted under section 5.3.1.2(b).

5.3.3 Prior to making any disclosure pursuant to section 5.3.1.4, 5.3.1.5 or 5.3.1.5A, a person being requested or demanded to disclose the *confidential information* shall advise the person affected by the request or demand as soon as reasonably practicable so as where possible to permit the affected person to challenge such request or demand or seek terms and conditions in respect of any such disclosure.

5.3.4 In making any disclosure pursuant to section 5.3.1.6, the disclosing person shall advise the person affected by the disclosure as soon as is reasonably practicable and shall use all reasonable endeavours to protect the confidentiality of the *confidential information* insofar as may be reasonably practicable in the circumstances.

5.3.5 Where the *IESO* makes any disclosure pursuant to section 5.3.1.8:

5.3.5.1 [Intentionally left blank – section deleted]

5.3.5.2 the *transmitter* to whom the disclosure is made shall use the *confidential information* so disclosed solely for the purposes referred to in section 5.3.1.8 and shall use all reasonable endeavours to protect the confidentiality of such *confidential information*.

5.3.6 Where the *IESO* makes any disclosure pursuant to section 5.3.1.9:

5.3.6.1 the *IESO* shall advise the *market participant* affected by the disclosure as soon as is reasonably practicable in the circumstances; and

5.3.6.2 the *market participant* to whom the disclosure is made shall use the *confidential information* so disclosed solely for the purposes referred to in section 5.3.1.9 and shall use all reasonable endeavours to protect the confidentiality of such *confidential information* as may be reasonably practicable in the circumstances.

5.3.7 Where the *IESO* proposes to disclose any *confidential information* pursuant to section 5.3.1.12 the *IESO* shall either require the *market monitoring unit* to demonstrate that their governing documents limit further disclosure, or enter into a non-disclosure agreement with the *market monitoring unit.* The *market monitoring unit's* governing documents or non-disclosure agreement shall:

5.3.7.1 establish a legally enforceable obligation to treat *confidential information* provided by the *IESO* as confidential. Such obligation shall be of a continuing nature and survive the termination of any investigation for which the *confidential information* has been requested;

5.3.7.2 require the *market monitoring unit* to whom the disclosure is made to promptly notify the *IESO* of any third party requests for additional disclosure of the *confidential information* and seek appropriate relief to prevent or, if it is not possible to prevent, to limit disclosure in the event that a subpoena or other compulsory process seeks to require disclosure of *confidential information* provided by the *IESO*;

5.3.7.3 require the *market monitoring unit* to whom the disclosure is made to use the *confidential information* so disclosed solely for the purposes referred to in section 5.3.1.12, and to use all reasonable endeavours to protect the confidentiality of such *confidential information* as may be reasonably practicable in the circumstances; and

5.3.7.4 require the *market monitoring unit* to whom the disclosure is made to destroy or return *confidential information* provided by the *IESO* at the conclusion or resolution of the investigation or five *business days* after a request to destroy or return *confidential information* from the *IESO* is received by the *market monitoring unit*.

5.3.8 Prior to making any disclosure pursuant to section 5.3.1.12, the *IESO* shall advise the *market participant* affected by the request as soon as reasonably practicable so as where possible to permit the affected *market participant* to challenge such request or seek terms and conditions in respect of any such disclosure. The *IESO* shall not be required to advise the affected *market participant* if the *IESO* reasonably determines that such notification will jeopardize the investigation.

5.3.9 *Confidential information* provided by a *market monitoring unit* to the *IESO* shall be destroyed or returned to the *market monitoring unit* that provided the *confidential information* at the conclusion or resolution of the investigation or five *business days* after a request to destroy or return *confidential information* from the *market monitoring unit* is received by the *IESO*.

5.3.10 Prior to making any disclosure pursuant to section 5.3.1.13, the *IESO* shall enter into a non-disclosure agreement directly with, or with the consultant of, a *market participant,* a *connection applicant,* or with a person planning to construct or modify a *facility*. The non-disclosure agreement shall:

5.3.10.1 establish a legally enforceable obligation to treat *confidential information* provided by the *IESO* as confidential. Such obligation shall be of a continuing nature and survive the completion of any reliability based power system study for which the *confidential information* was required;

5.3.10.2 require that the *confidential information* so disclosed is used solely for the purposes referred to in the non-disclosure agreement and in section 5.3.1.13, and to use all reasonable efforts to protect the confidentiality of such *confidential information*; and

5.3.10.3 require the destruction or return of the *confidential information* provided by the *IESO* at the conclusion of the reliability based power system study, or five *business days* after a request for the destruction or return of the *confidential information* from the *IESO* is received.

5.4 Classification of Information

5.4.1 The *IESO* shall establish the following three levels of *confidentiality classification* for information that may be in the possession or control of the *IESO*:

5.4.1.1 public;

5.4.1.2 [Intentionally left blank]

5.4.1.3 [Intentionally left blank]

5.4.1.4 [Intentionally left blank]

5.4.1.5 confidential; and

5.4.1.6 highly confidential.

5.4.2 Subject to section 5.4.3, information in the possession or control of the *IESO* that is listed in the *information confidentiality catalogue* and that is identified therein as:

5.4.2.1 public is information that is not *confidential information* including, but not limited to, information required by the *market rules* or the *licence* of the *IESO* to be *published*, and may be disclosed to, accessed by, reproduced or used by any person without restriction;

5.4.2.2 [Intentionally left blank]

5.4.2.3 [Intentionally left blank]

5.4.2.4 [Intentionally left blank]

5.4.2.5 confidential is confidential information that is provided to the IESO by a market participant, a standards authority, a security coordinator, a control area operator, an interconnected transmitter, or that is provided to the IESO by a person other than a market participant and that relates to a market participant; or that originates with or is created by the IESO and that relates to a market participant, and may only be disclosed by the IESO to or accessed by:

a. where the *confidential information* was provided to the *IESO* by a person, that person;

b. any person that the *IESO* has reasonable grounds to believe has been authorized by the person referred to in section 5.4.2.5(a) to access or receive such *confidential information*;

c. any authorized person within the *IESO*; and

d. the *market participant* to whom the *confidential information* relates.

5.4.2.6 highly confidential is *confidential information* that is provided to the *IESO* by a *market participant,* or by a person other than a *market participant,* or that originated within or is created by the *IESO*, and requires restricted access within the *IESO*, and may only be disclosed by the *IESO* to or accessed by:

a. where the *confidential information* was provided to the *IESO* by a person, that person;

b. any person that the *IESO* has reasonable grounds to believe has been authorized by the person referred to in section 5.4.2.6(a) to access or receive such *confidential information*; and

c. any person within the *IESO* that has the required security clearance assigned by the *IESO* and requires the *confidential information* for the purpose of the due performance of that person's duties and responsibilities.

5.4.3 Where:

5.4.3.1 the *information confidentiality catalogue* provides, in respect of any particular item of *confidential information*, that such *confidential information* is to be automatically re-classified within a different *confidentiality classification* following the expiry of the period of time identified in the *information confidentiality catalogue*, such *confidential information* shall be deemed for all purposes to be re-classified within such other *confidentiality classification* on and after the expiry of such period of time;

5.4.3.2 *confidential information* is re-classified by the *IESO* within a different *confidentiality classification* in accordance with any one of sections 5.5.3 to 5.5.6, such *confidential information* shall be deemed for all purposes to be re-classified within such other *confidentiality classification* on and after the date of such re-classification.

5.4.4 Where the *IESO* amends the *information confidentiality catalogue* to include an additional item of information, the *IESO* shall classify such information within the *confidentiality classification* that is, in the *IESO's* opinion, appropriate having regard to:

5.4.4.1 the adverse impact that disclosure of the information may reasonably be expected by the *IESO* to have on:

a. the person that provides the information;

b. the person to whom the information relates or such other person as the *IESO* has reasonable grounds to believe may be adversely affected by disclosure of the information;

c. the efficient operation of the *IESO-administered markets*;

d. the *reliable* operation of the *IESO-controlled grid*;

e. the *IESO*; and

f. the security of the *integrated power system*, the *IESO-administered markets* or those of neighbouring jurisdictions.

5.4.4.2 [Intentionally left blank]

5.4.4.3 [Intentionally left blank]

5.4.4.4 [Intentionally left blank]

5.4.4.5 [Intentionally left blank]

5.4.4.6 the proprietary nature and degree of confidentiality of the information, to the extent known by the *IESO*; and

5.4.4.7 the *IESO's* obligations relating to confidentiality of and access to information under the *market rules*, *applicable law* or any agreement to which the *IESO* is a party.

5.4.5 Where a *market participant* provides to the *IESO* information that is not listed in the *information confidentiality catalogue*, the *IESO* shall:

5.4.5.1 subject to sections 5.4.6, 5.4.7, 5.4.9.2 and 5.4.10, classify that information within the *confidentiality classification* designated by the *market participant* in accordance with section 5.4.11 at the time that it provides such information to the *IESO* or pursuant to section 5.4.9.2(b); and

5.4.5.2 respect any restrictions requested by the person to be imposed in respect of the disclosure, use, reproduction or provision of access to such information that are additional to the restrictions pertaining to that *confidentiality classification* as described in section 5.4.2 unless, in the *IESO's* opinion, such additional restrictions:

a. would interfere with the ability of the *IESO* to maintain the *reliability* of the *IESO-controlled grid* or to operate the *IESO-administered markets* in an efficient manner; or

b. are inconsistent with the *IESO's* obligations relating to confidentiality of and access to information under the *market rules*, *applicable law* or any agreement to which the *IESO* is a party.

5.4.6 Where the *IESO* disagrees with the *confidentiality classification* designated by a *market participant* pursuant to section 5.4.5.1, the *IESO* shall so notify the *market participant*, which notice shall specify:

5.4.6.1 the grounds upon which the *IESO* disagrees with the *confidentiality classification* designated by the *market participant*;

5.4.6.2 the *confidentiality classification* that the *IESO* considers to be appropriate for the information; and

5.4.6.3 the time within which the *market participant* may make representations to the *IESO* in support of the *confidentiality classification* designated by it.

5.4.7 Following the time noted in section 5.4.6.3, and after consideration of any representations made by the *market participant* pursuant to that section, the *IESO* shall:

5.4.7.1 where it agrees with the *confidentiality classification* designated by the *market participant*, classify the information within such *confidentiality classification*; or

5.4.7.2 where it continues to disagree with the *confidentiality classification* designated by the *market participant*, classify the information within the *confidentiality classification* referred to in section 5.4.6.2 or, subject to section 5.4.8, such other *confidentiality classification* that the *IESO* considers to be appropriate for the information,

and shall so notify the *market participant*.

5.4.8 For the purposes of section 5.4.7.2, the *IESO* shall not classify the information within a *confidentiality classification* other than the *confidentiality classification* referred to in section 5.4.6.2 unless such other *confidentiality classification* has, pursuant to section 5.4.2, associated with it provisions relating to disclosure and access that are more restrictive than those associated with the *confidentiality classification* referred to in section 5.4.6.2.

5.4.9 Where a *market participant* fails to designate a *confidentiality classification* for information submitted to the *IESO* pursuant to section 5.4.5.1 at the time at which it submits such information to the *IESO*, the *IESO* shall:

5.4.9.1 as soon as reasonably practicable following receipt of the information, notify the *market participant* that it must, within five *business days* of the date of receipt of the notice, designate a *confidentiality classification* for the information, failing which the *IESO* will classify the information within the confidential *confidentiality classification*; and

5.4.9.2 temporarily classify the information within the confidential *confidentiality classification* until:

a. the expiry of the period referred to in section 5.4.9.1 or within such longer period of time as may be agreed between the *IESO* and the *market participant*; or

b. the date on which the *market participant* designates a *confidentiality classification* for the information,

whichever is the earlier.

5.4.10 Where a *market participant* fails to designate a *confidentiality classification* for information submitted to the *IESO* pursuant to section 5.4.5.1 within the time referred to in section 5.4.9.2(a), the *IESO* shall classify the information within the confidential *confidentiality classification*.

5.4.11 For the purposes of sections 5.4.5.1 and 5.4.9.2(b), a *market participant* shall designate the *confidentiality classification* for information submitted pursuant to those sections having regard to:

5.4.11.1 the adverse impact that disclosure of the information may reasonably be expected by the *market participant* to have on itself;

5.4.11.2 the adverse impact that disclosure of the information may reasonably be expected by the *market participant* to have on any person to whom the information relates or on such other person as the *market*

participant may have reasonable grounds to believe may be adversely affected by disclosure of the information;

5.4.11.3 the proprietary nature and degree of confidentiality of the information; and

5.4.11.4 the *market participant's* obligations relating to confidentiality of and access to information under the *market rules*, *applicable law* or any agreement to which the *market participant* is a party.

5.5 Reclassification of Information

5.5.1 The *confidentiality classification* of any *confidential information* that is referred to in the *information confidentiality catalogue*, that is in the possession or control of the *IESO* and that has not been automatically re-classified in accordance with section 5.4.3.1 shall be reviewed by the *IESO*:

5.5.1.1 in the case of *confidential information* other than *confidential information* classified as highly confidential, no less than once in every three calendar years; and

5.5.1.2 in the case of *confidential information* classified by the *IESO* as highly confidential, no less than once in every seven calendar years,

with a view to determining, in accordance with section 5.5.2, whether the *confidential information* can be re-classified within a *confidentiality classification* that has, pursuant to section 5.4.2, associated with it provisions relating to disclosure or access that are less restrictive than those associated with the existing *confidentiality classification*.

5.5.2 The *IESO* shall make the determination referred to in section 5.5.1 having regard to the factors noted in section 5.4.4.

5.5.3 Where the *IESO* determines, in accordance with the review conducted pursuant to section 5.5.1 that *confidential information* can be re-classified within another *confidentiality classification* that has, pursuant to section 5.4.2, associated with it provisions relating to disclosure or access that are less restrictive than the existing *confidentiality classification*, the *IESO* shall:

5.5.3.1 [Intentionally left blank]

5.5.3.2 [Intentionally left blank]

5.5.3.3 where the *confidential information* was provided by a *market participant* or relates to a particular *market participant*, notify the *market participant* that provided the *confidential information* or to which the *confidential information* relates of its intention to re-classify the *confidential information*, which notice shall specify:

a. the grounds upon which the *IESO* has determined it appropriate to re-classify the *confidential information*;

b. the *confidentiality classification* that the *IESO* considers appropriate for purposes of the re-classification of the *confidential information*; and

c. the time within which the *market participant* may object to the re-classification of the *confidential information*.

5.5.4 Where:

5.5.4.1 a *market participant* fails, within the time referred to in section 5.5.3.3(c), to object to the re-classification of *confidential information* that relates to it but that was not provided by it to the *IESO*, the *IESO* may re-classify the information within the *confidentiality classification* referred to in section 5.5.3.3(b) or within such other *confidentiality classification* that has, pursuant to section 5.4.2, associated with it provisions relating to disclosure or access that are more restrictive than the *confidentiality classification* referred to in section 5.5.3.3(b), and shall notify the *market participant* accordingly;

5.5.4.2 a *market participant* fails, within the time referred to in section 5.5.3.3(c), to object to the re-classification of *confidential information* that was provided by it to the *IESO*, the *IESO* shall not re-classify the *confidential information*; or

5.5.4.3 a *market participant* objects to the re-classification of *confidential information* within the time referred to in section 5.5.3.3(c), the *IESO* shall not re-classify the *confidential information* except as may be agreed between the *IESO* and the *market participant*.

5.5.5 The *IESO* shall, at the request of a *market participant*, re-classify *confidential information* provided by that *market participant* within a *confidentiality classification* that has, pursuant to section 5.4.2, associated with it provisions relating to disclosure or access that are less restrictive than the existing *confidentiality classification* provided that the *IESO* is satisfied that such re-

classification would not be inconsistent with the factors referred to in section 5.4.4.

5.5.6 Where a *market participant* indicates, at the time at which it designates a *confidentiality classification* for *confidential information* pursuant to section 5.4.5.1, that the *confidential information* may be automatically re-classified within a *confidentiality classification* that has, pursuant to section 5.4.2, associated with it provisions relating to disclosure or access that are less restrictive than the existing *confidentiality classification*, the *IESO* shall re-classify such *confidential information* accordingly provided that the *IESO* is satisfied that such re-classification would not be inconsistent with the factors referred to in section 5.4.4.

5.5.7 Amendments to the *information confidentiality catalogue* shall be subject to review by the *technical panel* and approval by the *IESO Board* until the end of 2003.

5.6 Cost of Access and Electronic Data Sharing

5.6.1 Nothing in this section 5 shall prevent information which is made available by means of electronic communications from being provided on a read-only basis.

5.6.2 Each *market participant* and any other person accessing, retrieving or storing information *published* or otherwise made available by the *IESO* shall be responsible for its own costs of accessing, retrieving or storing such information.

5.7 Conditions of Access

5.7.1 Where a request for access to or disclosure of information in the possession or control of the *IESO* is made by a *market participant* pursuant to these *market rules*, the *IESO* shall only provide such access or disclosure if:

5.7.1.1 the *IESO* is satisfied that it is not precluded by these *market rules* from providing such access or disclosure to the *market participant;* and

5.7.1.2 the provision of such access or disclosure would not impose a significant burden on the *IESO*, having regard to the *IESO's* resources.

5.7.2 Where the *IESO* makes *confidential information* accessible by means of electronic communications, the *IESO* shall implement access control protocols that differentiate between *market participants* but that need not differentiate between individuals, whether within the same *market participant* or otherwise.

6. Enforcement

6.1 Introduction

6.1.1 This section sets forth the rules pursuant to which the *IESO* shall monitor, assess and enforce compliance with the *market rules*, including by means of the imposition of financial penalties, the issuance of non-compliance letters, *suspension orders, termination orders* and *disconnection orders* and the taking of such other enforcement actions as provided for in these *market rules*.

6.1.2 The *IESO* shall undertake such monitoring as it considers necessary to determine whether *market participants* are complying with the *market rules*.

6.2 Procedures Concerning Alleged Breaches of the Market Rules

6.2.1 This section shall not apply to the issuance by the *IESO* of a *suspension order* or *termination order*, which shall be governed by the provisions of section 6.3A or 6.4, respectively, or to the issuance by the *IESO* of an order referred to in section 6.2A.1, which shall be governed by the applicable provisions of section 6.2A and 6.5.

6.2.1A This section 6 shall not apply in respect of:

6.2.1A.1 a breach of any performance standard set forth in the *market rules*; or

6.2.1A.2 a failure to pass a test set forth in the *market rules* or, where applicable, the *Ontario power system restoration plan*,

by an *ancillary service provider* in the provision of *regulation* or *black start capability* under a *contracted ancillary service* contract, which shall be governed, by the provisions of section 7 and by the provisions of sections 4.10.2.1 and 4.10.2.2 of Chapter 5.

6.2.2 Where the *market rules* provide for consequences or sanctions in respect of a breach by a *market participant* of a particular *market rule* or *market rules*, those consequences or sanctions shall apply in the circumstances and in the manner provided for in the relevant sections of the *market rules* in addition to such sanctions as may be imposed pursuant to this section 6.2.

6.2.3 If the *IESO* considers, on its own initiative or upon receipt of written information from any person, that a *market participant* may have breached or may be

breaching the *market rules* and that, in the circumstances and if the breach is established, it would be appropriate that a sanction or sanctions be imposed on that *market participant*, the *IESO* shall notify the *market participant* of:

6.2.3.1 details of the alleged breach and of the time within which the breach must be remedied;

6.2.3.2 details of the evidence on the basis of which the *IESO* considers that the *market participant* may have breached or may be breaching the *market rules*;

6.2.3.3 details of the sanctions which may be imposed if the breach is established;

6.2.3.4 the time within which the *market participant* may make written representations in response to the allegations; and

6.2.3.5 the right of the *market participant* to request a meeting with the *IESO* to discuss the matter.

6.2.4 Following expiry of the time noted in section 6.2.3.4, and after consideration of any representations made by the *market participant* pursuant to that section, the *IESO* may:

6.2.4.1 determine that the *market participant* has not breached the *market rules*;

6.2.4.2 subject to section 6.2.5, determine that the *market participant* is in breach of the *market rules*;

6.2.4.3 request that the *market participant* provide further information in relation to the alleged breach; or

6.2.4.4 conduct such further investigation into the matter as the *IESO* determines appropriate.

6.2.5 Where a *market participant* has requested a meeting pursuant to section 6.2.3.5, the *IESO* shall provide the *market participant* with a reasonable opportunity to meet with the *IESO* to discuss the allegations. In such case, the *IESO* shall not make the determination noted in section 6.2.4.2 until such reasonable opportunity has been given.

6.2.6 A *market participant* shall comply with any request for information made by the *IESO* pursuant to section 6.2.4.3.

6.2.7 Subject to section 6.2.7A, where the *IESO* determines that a *market participant* has breached the *market rules*, the *IESO* may by order do any one or more of the following:

6.2.7.1 direct the *market participant* to do, within a specified period, such things as may be necessary to comply with the *market rules*;

6.2.7.2 direct the *market participant* to cease, within a specified period, the act, activity or practice constituting the breach;

6.2.7.3 impose additional or more stringent record-keeping or reporting requirements on the *market participant*;

6.2.7.4 issue a non-compliance letter in accordance with section 6.6;

6.2.7.5 impose financial penalties in accordance with section 6.6 indicating the time within which payment of the financial penalty must be made to the *IESO*, provided that no such penalties shall be imposed unless the *IESO* is satisfied that the breach could have been avoided by the exercise of due diligence by the *market participant* or that the *market participant* acted intentionally; or

6.2.7.6 take such other action as may be provided for in Appendix 3.1 in respect of the *market rule* that has been breached by the *market participant*.

6.2.7.7 [Intentionally left blank – section deleted]

6.2.7A If the *IESO* is satisfied that the *market participant* has breached section 10A of Chapter 1, and the *IESO* proposes to issue one or more orders under section 6.2.7, the *IESO* shall serve a *notice of intention* on the *market participant* in accordance with section 6.2B. The *IESO* may include in the *notice of intention* any or all alleged breaches of the *market rules* that were included in the notice issued under section 6.2.3. If the *IESO* does not include in the *notice of intention* an alleged breach described in the notice issued under section 6.2.3, excluding an alleged breach of section 10A of Chapter 1, then the *IESO* may make one or more orders under section 6.2.7 respecting that alleged breach.

6.2.8 An order imposing financial penalties on a *market participant* pursuant to section 6.6 shall, subject to section 2.3.3, be considered to create an obligation under the *market rules* to pay the amount stated in the order and such amount may, without prejudice to any other manner of recovery available at law, be recovered accordingly.

6.2.9 Failure to comply with an order of the *IESO* made pursuant to section 6.2.7 constitutes a breach of the *market rules*.

6.2A Persistent Breaches of the Market Rules

6.2A.1 If a *market participant* has breached the *market rules* on a persistent basis, the *IESO* may:

6.2A.1.1 issue that *market participant* a *suspension order* under section 6.3A;

6.2A.1.2 issue that *market participant* a *termination order* under section 6.4; or

6.2A.1.3 deregister some or all of the *market participant's registered facilities* under section 6.5.

6.2A.2 Where the *IESO* intends to act pursuant to section 6.2A.1, the *IESO* shall provide the *market participant* with a notice stating:

6.2A.2.1 the nature of the action to be taken;

6.2A.2.2 the grounds and any evidence on which the *IESO* relies on in support of the intended action;

6.2A.2.3 the time within which the *market participant* may make written representations to the *IESO* as to why such action should not be taken; and

6.2A.2.4 the right of the *market participant* to request a hearing before the *IESO Board* or a committee of the *IESO Board* established for such purpose to show cause why such action should not be taken.

6.2A.3 The *IESO* shall provide a copy of any notice issued under section 6.2A.2 to the *OEB* and to the *transmitter, distributor* and/or other *market participant* to whose *facilities* the *market participant's facilities* who is the subject of the notice are connected.

6.2A.4 If the *market participant* has requested a hearing, the *IESO Board* or a committee of the *IESO Board* established for such purpose shall conduct a hearing providing the *market participant* with a reasonable opportunity to show cause as to why such action should not be taken against it. Following the hearing, the *IESO Board* or the committee of the *IESO Board* established for such purpose may:

6.2A.4.1 approve the action that the *IESO* intends to take; or

6.2A.4.2 make any other appropriate order, including an order referred to in section 6.2.7.

6.2A.5 If the *market participant* has not requested a hearing, the *IESO* shall consider any written representations received from the *market participant* and may take any action specified in the notice issued under section 6.2A.2 or make any other appropriate order, including an order referred to in section 6.2.7.

6.2A.6 The *IESO* shall *publish* a notice of any actions taken under section 6.2A.4 or 6.2A.5 and provide a copy to the *OEB* and the *transmitter*, *distributor* and/or other *market participant* to whose *facilities* the *market participant's facilities* who is the subject of the notice are connected.

6.2B Alleged Breaches of Section 10A of Chapter 1

6.2B.1 For the purposes of section 6.2B, excluding sections 6.2B.19 and 6.2B.20, a reference to section 10A of Chapter 1 shall be deemed to include all breaches described in the *notice of intention*.

6.2B.2 If the *IESO* is satisfied that the *market participant* has breached section 10A of Chapter 1, the *IESO* shall, prior to making any order under section 6.2.7, serve a written *notice of intention* on the *market participant*. The notice shall set out the following:

6.2B.2.1 the *market rules* that the *IESO* is satisfied that the *market participant* has breached;

6.2B.2.2 the reasons the *IESO* intends to determine that the *market participant* has breached section 10A of Chapter 1;

6.2B.2.3 the proposed order or orders under section 6.2.7;

6.2B.2.4 the *market participant's* right to contest the *notice of intention* pursuant to section 6.2B.3; and

6.2B.2.5 the time within which the *market participant* may contest the *notice of intention*.

6.2B.3 If the *market participant* wishes to contest the *notice of intention*, it shall serve a *response to the notice of intention* on the *IESO* within 20 *business days* of receipt of the *notice of intention*.

6.2B.4 If the *market participant* does not contest the *notice of intention* within 20 *business days* of the receipt of the *notice of intention*, the *IESO* may determine that the *market participant* has breached section 10A of Chapter 1 and impose one or more orders under section 6.2.7.

6.2B.5 If the *market participant* contests the *notice of intention*, the *market participant* and the *IESO* shall attempt to resolve the matter through good faith negotiations in accordance with sections 2.5.3A and 2.5.3B, except that the *response to the notice of intention* shall replace the *notice of dispute* referred to in section 2.5.3A and shall be served in accordance with section 2.5.1A.4D.

6.2B.6 Notwithstanding sections 2.5.3C and 2.5.4, if the parties are unable to resolve the matter through good faith negotiations, the mediation process described in section 2.6 shall apply and either party may file with the *secretary* on written notice to each other party a copy of the *notice of intention* and *response to the notice of intention* together with proof of service. The *secretary* and *mediator* shall rely on the *notice of intention* and *response to the notice of intention* in lieu of the *notice of dispute* and *response* for the purposes of section 2.6. The *IESO* shall provide a summary of the matter for *publication* in accordance with section 2.9.2.1.

6.2B.7 If the parties are unable to resolve the matter through the mediation process, then within 5 *business days* of the filing of the written notice terminating the mediation process, as referred to in section 2.6.1B, 2.6.13 or 2.6.16, the *market participant* shall file with the *secretary* and serve on the *IESO* a *notice to elect* electing one of the following available options:

6.2B.7.1 that the matter be referred to an *arbitrator* pursuant to the process described in section 2.7;

6.2B.7.2 that the *IESO* apply to the *Ontario Energy Board* to make a determination and findings of fact as described in section 6.2B.11; or

6.2B.7.3 not to pursue the matter under either subsections 6.2B.7.1 or 6.2B.7.2.

6.2B.8 Where the *market participant* elects not to pursue the matter under section 6.2B.7.3 or does not make any election as described in section 6.2B.7, the *IESO* may determine that the *market participant* has breached section 10A of Chapter 1 and impose one or more orders under section 6.2.7.

6.2B.9 Where the *market participant* elects that the matter be referred to an *arbitrator* pursuant to section 6.2B.7.1, section 2.7 shall apply. For the purposes of section 2.7, the *IESO* shall be deemed to be the *applicant* and the *market participant* shall be deemed to be the *respondent*.

6.2B.10 Where the *market participant* elects that the *IESO* apply to the *Ontario Energy Board* pursuant to section 6.2B.7.2, the *IESO* shall bring the application to the *Ontario Energy Board* within 20 *business days* of the service of the *notice to elect*.

6.2B.11 In an application brought pursuant to section 6.2B.10, the *IESO* shall request that the *Ontario Energy Board* make the following:

6.2B.11.1 a determination of whether the *market participant* has breached section 10A of Chapter 1; and

6.2B.11.2 findings of fact relevant to the imposition of one or more orders by the *IESO* under section 6.2.7.

6.2B.12 Where the *IESO* applies for a hearing before the *Ontario Energy Board* pursuant to section 6.2B.10 and the *Ontario Energy Board* dismisses the proceeding without a hearing under subsection 4.6(1)(b) of the *Statutory Powers Procedure Act*, the *notice to elect* shall be deemed to be a request for arbitration under section 6.2B.7.1 and the *IESO* shall refer the matter to an *arbitrator* in accordance with section 6.2B.9.

6.2B.13 Where the *Ontario Energy Board* holds a hearing referred to in section 6.2B.11 and determines that the *market participant* has not breached section 10A of Chapter 1, subject to any rights of appeal or review, the *IESO* shall adopt the *Ontario Energy Board*'s findings.

6.2B.14 Where the *Ontario Energy Board* holds a hearing referred to in section 6.2B.11 and determines that the *market participant* has breached section 10A of Chapter 1, subject to any rights of appeal or review, the matter shall return to the *IESO* and the *IESO* shall adopt the *Ontario Energy Board's* determination on breach.

6.2B.15 Where the matter returns to the *IESO* under section 6.2B.14, the *IESO* may issue one or more orders pursuant to section 6.2.7 and, in doing so:

6.2B.15.1 shall adopt and apply all findings of fact made by the *Ontario Energy Board;* and

6.2B.15.2 may adopt and apply any information from the record of the hearing before the *Ontario Energy Board*,

that are relevant to the order or orders under section 6.2.7 but may not rely on any additional evidence.

6.2B.16 If the *market participant* wishes to dispute the *IESO*'s order or orders issued pursuant to section 6.2B.15, it shall serve a *notice of dispute* on the *IESO* within 20 *business days* of receipt of the order or orders.

6.2B.17 Where the *market participant* disputes the order or orders issued by the *IESO* pursuant to section 6.2B.15, the *market participant* and the *IESO* shall attempt to resolve the matter in accordance with sections 2.5 and 2.6.

6.2B.18 The arbitration process set out in section 2.7 shall not apply to disputes as described in section 6.2B.16. An order issued under section 6.2B.15 may be

appealed as provided for in section 36 of the *Electricity Act, 1998* upon the filing of a notice under section 2.6.1B, 2.6.13 or 2.6.16 terminating the mediation process.

6.2B.19 The *IESO* shall, pursuant to section 6.2B.2, serve a *notice of intention* no later than six years after the day on which the alleged breach of section 10A of Chapter 1 was discovered by the *IESO*. Where the *IESO* fails to serve a *notice of intention* within the time provided, no finding of breach of section 10A of Chapter 1 shall be made pursuant to the *market rules* in respect of that conduct.

6.2B.20 For the purposes of section 6.2B.19, the term "discovered" has the meaning prescribed in section 5(1) of the *Limitations Act, 2002*.

6.3 Events of Default

6.3.1 An *event of default* occurs if a *market participant* or the person that has provided *prudential support* or *capacity prudential support* in relation to the *market participant*:

6.3.1.1 does not make a payment in full required under the *market rules* when due;

6.3.1.2 fails to provide payment in full of any amount claimed by the *IESO* under any *prudential support* or *capacity prudential support;*

6.3.1.3 fails to provide and maintain *prudential support* or *capacity prudential support* required to be supplied under the *market rules* within the time required;

6.3.1.4 has a licence (including a *licence*), permit or other authorization necessary to carry on its principal business suspended, revoked or otherwise cease to be in full force and effect, provided that where a *market participant* holds more than one *licence* and only one such *licence* has been suspended, revoked or otherwise ceases to be in full force and effect, the *event of default* and any action taken by the *IESO* with respect thereto shall relate only to such *licence*;

6.3.1.5 ceases or threatens to cease to carry on its business or a substantial part of its business;

6.3.1.6 becomes insolvent or is unable to pay all or some of its debts when they fall due for payment;

6.3.1.7 seeks to enter into an arrangement, composition or compromise with, or makes an assignment for the benefit of, all or any class of its creditors;

6.3.1.8 has a receiver or receiver and manager or person having a similar or analogous function under the laws of any relevant jurisdiction appointed in respect of any of its property that is used in or relevant to the performance of its obligations under the *market rules* or its *licence*;

6.3.1.9 is the subject of an order appointing an administrator, liquidator, trustee in bankruptcy or person having a similar or analogous function under the laws of any jurisdiction;

6.3.1.10 is wound up, dissolved, or otherwise has ceased to exist or is the subject of an application for winding up or dissolution, or any analogous procedure, under the laws of any jurisdiction, unless the notice of winding up or dissolution is discharged or withdrawn; or

6.3.1.11 ceases to satisfy any material requirement imposed upon it as a condition of its authorization to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid*.

6.3.2 A *market participant* shall notify the *IESO* immediately upon:

6.3.2.1 the occurrence of an *event of default* or any circumstance that may give rise to an *event of default* referred to in sections 6.3.1.4 to 6.3.1.11; or

6.3.2.2 the appointment of a receiver or receiver and manager or person having a similar or analogous function under the laws of any relevant jurisdiction in respect of any property of the *market participant* or the *market participant's prudential support* provider, or *capacity prudential support* provider.

6.3.3 Where a *market participant* or a person providing *prudential support* or *capacity prudential support* on behalf of that *market participant* commits an *event of default,* the *IESO* may:

6.3.3.1 issue to the *market participant* a *notice of intent to suspend* stating that the *market participant* will be suspended unless it remedies the *event of default* within 2 *business days* or such longer period as specified in the notice;

6.3.3.2 immediately draw upon part or all of the *market participant's prudential support*or *capacity prudential support* for either the amount of any money owing to the *IESO* under the *market rules* or where the *market participant's prudential support* or *capacity prudential support* is due to expire or terminate and has not been replaced as required under section 5.2.5, 5A.2.3 or 5B.2.4 of Chapter 2, the undrawn part of the *prudential support* notwithstanding the provisions of section 5.7.2.5 of Chapter 2 until such time as the *market participant* has replaced its *prudential support* or *capacity prudential support*; and

6.3.3.3 set-off any amounts due or credited to the *market participant* under the *market rules,* including those set out in section 4.8.2 of Chapter 9, and any program administered through the billing and *settlement* systems of the *IESO* against any amounts owed by the *market participant.*

6.3.4 Where the *IESO* issues a *notice of intent to suspend* under section 6.3.3.1 or a *suspension order* under sections 6.3A.1.1 and 6.3A.1.2 to a *market participant* that is a party to a *physical bilateral contract,* the *IESO* shall:

6.3.4.1 deem any *physical bilateral contract quantities* to be zero for the period from the date the *event of default* occurs until it is remedied if that *market participant* is the *selling market participant*; or

6.3.4.2 rescind or refuse to accept any initial or revised *physical bilateral contract data* relating to a *dispatch day* after the date of the *event of default* if that *market participant* is the *buying market participant*.

6.3.5 [Intentionally left blank – section deleted]

6.3.6 A *market participant* may remedy an *event of default* by:

6.3.6.1 satisfying any outstanding financial or other obligations that gave rise to the *event of default,* including any applicable *default interest* and any costs and expenses incurred by the *IESO* as a result of the *event of default*; and

6.3.6.2 proving to the reasonable satisfaction of the *IESO* that the facts or circumstances which constituted the *event of default* no longer exist.

6.3.7 Notwithstanding that the *event of default* has been remedied, the *IESO* may impose any condition on the right of a *market participant* to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into,

through or out of the *IESO-controlled grid* that the *IESO* determines are appropriate, including:

6.3.7.1 establishing a lower *trading limit* in respect of the *market participant* than would otherwise be the case under section 5.3 of Chapter 2;

6.3.7.2 establishing a more frequent continuing schedule of payments than would otherwise be the case under Chapter 9; or

6.3.7.3 imposing a more stringent *prudential support obligation* than would otherwise be the case under section 5 of Chapter 2.

6.3A Suspension of a Market Participant

6.3A.1 The *IESO* may issue a *suspension order* to a *market participant* if:

6.3A.1.1 the *market participant* has not remedied an *event of default* within the time specified in the *notice of intent to suspend*;

6.3A.1.2 an *event of default* specified in sections 6.3.1.5 to 6.3.1.10 has occurred in relation to the *market participant*; or

6.3A.1.3 the *IESO* has determined under section 6.2A that a *suspension order* should be issued because the *market participant* has persistently breached the *market rules*.

6.3A.2 The *IESO* shall *publish* the details of the *suspension order* and provide a copy of the *suspension order* to the *OEB* and the *transmitter, distributor* and/or other *market participant* to whose *facilities* the suspended *market participant* is connected.

6.3A.3 To the extent specified in the *suspension order,* a *suspended market participant* is ineligible to trade or enter into any transaction in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid*.

6.3A.4 The *IESO* may do one or more of the following to give effect to a *suspension order*:

6.3A.4.1 reject any bid, offer, TR bid or TR offer submitted by the suspended market participant;

6.3A.4.2 set-off any amounts otherwise due to the *suspended market participant* against any amounts owed by the *suspended market participant* under the *market rules*;

6.3A.4.3 issue a disconnection order to the transmitter, distributor and/or other market participant to whose facilities the suspended market participant's facilities are connected and provide a copy to the OEB; or

6.3A.4.4 make such further order or issue such directions to the *suspended market participant* as the *IESO* determines appropriate.

6.3A.5 The *IESO* shall lift a *suspension order* if the *event of default* which triggered its issuance is remedied to the satisfaction of the *IESO* and there are no other *events of default* in existence with respect to the *suspended market participant*.

6.3A.6 Notwithstanding that the *suspension order* has been lifted, the *IESO* may impose any condition on the right of a *market participant* that has been subject of a *suspension order* to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid* that the *IESO* determines are appropriate, including the conditions noted in sections 6.3.7.1 to 6.3.7.3.

6.4 Termination of a Market Participant

6.4.1 The *IESO* may issue a *termination order* to a *market participant* if:

6.4.1.1 the market participant is a suspended market participant and has not remedied the event of default that triggered the suspension order within 5 business days of the issuance of the suspension order;

6.4.1.2 the *market participant* is a *suspended market participant* and has notified the *IESO* that the *market participant* is not likely to remedy the *event of default* that triggered the issuance of the *suspension order*;

6.4.1.3 the *market participant* has been wound up, dissolved, or otherwise has ceased to exist; or

6.4.1.4 the *IESO* has determined under section 6.2A that a *termination order* should be issued because the *market participant* has persistently breached the *market rules*.

6.4.2 The *IESO* shall *publish* the details of the *termination order* and provide a copy of the *termination order* to the *OEB* and to the *transmitter, distributor* and/or other

market participant to whose *facilities* the *terminated market participant's facilities* are connected.

6.4.3 When the *IESO* issues a *termination order*, it may at the same time, if it has not already done so, issue a *disconnection order* to the *transmitter, distributor* and/or other *market participant* to whose *facilities* the *terminated market participant's facilities* are connected and provide a copy to the *OEB*.

6.4.4 A *terminated market participant* that re-applies for authorization shall be required to comply with the provisions of section 3 of Chapter 2. The *IESO* may impose any conditions on the right of the *terminated market participant* to participate in *the IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of *the IESO-controlled grid* that the *IESO* determines are appropriate, including the conditions noted in sections 6.3.7.1 to 6.3.7.3.

6.5 De-Registration of a Market Participant's Facilities

6.5.1 The *IESO* may deregister some or all of a *market participant's registered facilities* if the *IESO* has determined under section 6.2A that the *market participant* has persistently breached the *market rules*.

6.5.2 Deregistering some or all of a *market participant's registered facilities* terminates all of the rights of the *market participant* in respect of those *registered facilities* to participate in the *IESO-administered markets* or in respect of those *registered facilities* to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid* in respect of those *registered facilities*.

6.5.3 If the *IESO* deregisters some or all of a *market participant's registered facilities*, it may at the same time issue a *disconnection order* to the relevant *transmitter, distributor* and/or other *market participant* to whose *facilities* the *market participant's facilities* which is subject of the deregistration are connected and provide a copy to the *OEB*.

6.5.4 A *market participant* that wishes to re-register *registered facilities* that have been deregistered shall comply with the provisions of section 2 of Chapter 7. The *IESO* may impose any conditions on right of the *market participant* to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid* that the *IESO* determines are appropriate, including the conditions noted in sections 6.3.7.1 to 6.3.7.3.

6.5A Disconnection Order

6.5A.1 Each *transmitter, distributor* and other *market participant* to whom a *disconnection order* is issued pursuant to sections 6.3A.4.3, 6.4.3 or 6.5.3 shall, subject to this section 6.5A, on the date and at the time specified in the *disconnection order*, *disconnect* the *facilities* or equipment referred to in the *disconnection order*.

6.5A.2 Nothing in this section 6.5A is intended to prevent a *transmitter, distributor* or other *market participant* from taking action to ensure the safety of any person, prevent the damage of equipment, or prevent the violation of any *applicable law*; provided, however, that such *transmitter, distributor* or other *market participant* shall coordinate to the fullest extent practicable any such action with the *IESO*.

6.5A.3 Without limiting the generality of section 8.3 of Chapter 1, a *disconnection order* may be issued by the IESO to a *transmitter, distributor* or other *market participant* pursuant to sections 6.3A.4.3, 6.4.3 or 6.5.3 by voice communication.

6.6 Non-compliance Letters and Financial Penalties

6.6.1 This section 6.6 sets forth the manner in which the *IESO* will pursuant to section 6.2.7 issue non-compliance letters and fix financial penalties to be imposed on *market participants* for breaches of the *market rules*.

6.6.2 Where the *IESO* has determined that it is appropriate to issue a letter of non-compliance or impose a financial penalty upon a *market participant*, the *IESO* shall:

6.6.2.1 determine the level of non-compliance by the *market participant* in accordance with section 6.6.3;

6.6.2.2 determine the rate of recurrence of non-compliance by the *market participant* in accordance with section 6.6.4;

6.6.2.3 based on the determinations made in accordance with sections 6.6.2.1 and 6.6.2.2, issue a non-compliance letter or impose a financial penalty; and

6.6.2.4 where a determination is made to impose a financial penalty, fix the amount of the penalty in accordance with section 6.6.6.

6.6.2A When determining the particular level of non-compliance referred to in section 6.6.2.1, the *IESO* shall establish:

- whether all of the conditions for a level have been met; and
- that the manner and time, proposed by the *market participant*, within which the non-compliance event will be remedied are reasonable under the circumstances.

If a *market participant*

- meets some but not all of the conditions of any single level; or
- proposes a manner and time in which the non-compliance event will be remedied that are not reasonable under the circumstances in the opinion of the *IESO*,

then the *IESO* shall assign what it considers to be the appropriate non-compliance level.

6.6.3 The *IESO* shall determine the level of non-compliance referred to in section 6.6.2.1 as follows:

6.6.3.1 Level "L1" shall apply where the *market participant*:

i. failed to comply, in part, with the requirements of a *market rule*, and
ii. on its own initiative informed the *IESO* on a timely basis of:
   - the reasons for the non-compliance, and
   - the manner and time in which the non-compliance will be remedied.

6.6.3.2 Level "L2" shall apply where the *market participant*:

i. failed to comply in whole with the requirements of a *market rule*, and
ii. on its own initiative informed the *IESO* on a timely basis of:
   - the reasons for the non-compliance, and
   - the manner and time in which the non-compliance will be remedied.

6.6.3.3 Level "L3" shall apply where the *market participant*:

i. failed to comply, in whole or in part, with the requirements of a *market rule*,

ii. did not on its own initiative inform the *IESO* on a timely basis of the non-compliance; but

iii. did inform, at the *IESO*'s request and within the time specified in the request, the *IESO* of:

- the reasons for the non-compliance, and
- the manner and time in which the non-compliance will be remedied.

6.6.3.4 Level "L4" shall apply where the *market participant*:

i. failed to comply, in whole or in part, with the requirements of a *market rule*,

ii. did not on its own initiative inform the *IESO* on a timely basis of the non-compliance; and

iii. did not inform, at the *IESO*'s request and within the time specified in the request, the *IESO* of:

- the reasons for the non-compliance, and
- the manner and time in which the non-compliance will be remedied.

6.6.4 The *IESO* shall determine the rate of recurrence of non-compliance referred to in section 6.6.2.2 based on the frequency and duration with which the *market participant* has been found by the *IESO* to be in breach of the *market rules*.

6.6.5 [Intentionally left blank – section deleted]

6.6.6 Where the *IESO* has determined, based on the determinations made under section 6.6.2, that the applicable sanction is the imposition of a financial penalty, the *IESO* shall, subject to section 6.6.6A, consider the factors listed in section 6.6.7 and impose a financial penalty on the *market participant* within the ranges set out in the following table.

Level of Non-Compliance	Range of Sanctions
L1	Non-compliance letter or up to $2,000.00
L2	Non-compliance letter or up to $4,000.00
L3	Non-compliance letter or up to $6,000.00
L4	$1,000.00 to $10,000.00

6.6.6A The *IESO* may impose on a *market participant* a financial penalty in excess of the amount otherwise provided for in section 6.6.6 and no greater than $1,000,000 per occurrence, where:

6.6.6A.1 the market participant has breached a market rule while a declaration that the IESO-controlled grid is in an emergency operating state or a high-risk operating state was in effect;

6.6.6A.2 the *market participant* breached a *market rule* while a declaration that *market operations* have been suspended was in effect;

6.6.6A.3 the *IESO Board* determines that the impact of the *market participant*'s breach of a *market rule* on either the *IESO-administered markets* or the *reliability* of the *integrated power system* is particularly severe; or

6.6.6A.4 the rate of recurrence of non-compliance by the *market participant* with the *market rules* is of such frequency or duration as to warrant the imposition of a higher financial penalty.

6.6.6B Where at least one of the conditions of 6.6.6A are met and the *IESO* has determined that the applicable sanction is the imposition of a financial penalty, the *IESO* shall, consider the factors listed in section 6.6.7 and impose a financial penalty on the *market participant* within the ranges set out in the following table.

	Non-Compliance Level (Severity and Breach History)							
Impact Level	**Low**		**Moderate**		**High**		**Severe**	
	Range Limit		Range Limit		Range Limit		Range Limit	
	Min	Max	Min	Max	Min	Max	Min	Max
Low Little or None	$2,000	$25,000	$2,000	$50,000	$3,000	$75,000	$5,000	$100,000
Medium Material	$2,000	$100,000	$4,000	$250,000	$6,000	$450,000	$10,000	$600,000
High Severe	$4,000	$250,000	$8,000	$500,000	$12,000	$750,000	$20,000	$1,000,000

The *IESO* shall establish the penalty range at the intersection of the determined impact level and non-compliance level in accordance with the applicable *market manual* which includes:

- The *IESO* shall determine the impact level by examining all the impacts of the breach under investigation and selecting an appropriate impact level.

- The *IESO* shall determine the non-compliance level by examining breach history contributions, severity, and any aggravating or mitigating adjustments.

6.6.7 In fixing the amount of the financial penalty within the ranges described in the tables set forth in sections 6.6.6 and 6.6.6B, the *IESO* shall have regard to:

6.6.7.1 the circumstances in which the breach occurred;

6.6.7.2 the severity of the breach;

6.6.7.3 the extent to which the breach was inadvertent, negligent, deliberate or otherwise;

6.6.7.4 the length of time the breach remained unresolved;

6.6.7.5 the actions of the *market participant* on becoming aware of the breach;

6.6.7.6 whether the *market participant* disclosed the matter to the *IESO* on its own or whether it was prompted to do so;

6.6.7.7 any benefit that the *market participant* obtained or may have obtained as a result of the breach;

6.6.7.8 any previous breach by the *market participant* of the *market rules* or of the conditions of its *licence*;

6.6.7.9 the actual or potential impact of the breach on other *market participants*;

6.6.7.10 the actual or potential impact of the breach on the *IESO-administered markets* as a whole;

6.6.7.10A the actual or potential impact of the breach on the *reliability* of the *integrated power system*;

6.6.7.11 any sanctions that may be imposed on the *IESO* by a *standards authority* as a result of the breach;

6.6.7.12 the immediacy of the threat that the breach poses to the *reliability* of the *integrated power system* or the *IESO-administered market*;

6.6.7.13 presence and quality of the *market participant*'s compliance program;

6.6.7.14 whether on its own initiative, a *market participant* has undertaken to reasonably compensate the *IESO-administered market* for the value of any benefit it obtained as a result of the breach; and

6.6.7.15 such other matters as the *IESO* considers appropriate.

6.6.8 Where Appendix 3.1 provides for the imposition of a formula-based penalty in respect of the breach of a *market rule*, the *IESO* may issue a letter of non-compliance pursuant to section 6.6.2.3 or impose a financial penalty upon the *market participant*, the amount of which shall be determined by the application of the following formula:

$$P = D \times T \times C$$

Where:

P = the amount of the financial penalty, in dollars

D = the deviation from the applicable obligation in the *market rules*, expressed in terms of MW, MVAR, kV, power factor or other determinant, as specified in Appendix 3.1 in respect of the particular *market rule*

T = the duration of the breach, expressed in hours or fractions of hours

C = the amount determined in accordance with section 6.6.9 in respect of the particular *market rule*

6.6.9 The amount C referred to in section 6.6.8 shall be determined, in respect of the breach of a particular *market rule*, by multiplying the *market price* prevailing at the time of the breach by an amount determined by the *IESO* having regard to the criteria set forth in section 6.6.7 and to the factors noted in sections 6.6.6A.1 to 6.6.6A.4, where applicable.

6.6.10 Where Appendix 3.1 specifies more than one sanction in respect of the breach of a particular *market rule*, the *IESO* may impose all of the sanctions so specified on the *market participant* provided that no financial penalty may be imposed in respect of a breach for which the *IESO* has issued a letter of non-compliance pursuant to section 6.6.2.3. Nothing in this section 6.6.10 shall prevent the *IESO* from imposing a financial penalty for failure by a *market participant* to remedy a breach in respect of which a letter of non-compliance has been issued or if there is any repetition or continuation of such breach.

6.6.10A In respect of a breach of section 7.5.8A of Chapter 7, the *IESO* may:

6.6.10A.1 issue a letter of non-compliance or impose a financial penalty upon the *market participant* pursuant to sections 6.6.2.3, and 6.6.6; and

6.6.10A.2 adjust *settlement amounts* paid or payable to a *registered market participant* such as *transmission rights* payments, congestion management *settlement* credits or other *settlement amounts* that the *registered market participant* received or avoided due to an act or omission or a course of conduct of either the *registered market participant* alone or the *registered market participant* by agreement or arrangement with one or more other *market participants* that led to the breach of section 7.5.8A of Chapter 7.

6.6.11 Nothing in this section 6.6 shall preclude the *IESO* from making an order under one or more of sections 6.2.7.1, 6.2.7.2, 6.2.7.3 or 6.2.7.6 in respect of a breach of the *market rules* with respect to which a sanction has been imposed pursuant to this section 6.6.

6.6.12 [Intentionally left blank]

6.6.12.1 [Intentionally left blank]

6.6.12.2 [Intentionally left blank]

6.6.13 [Intentionally left blank – section deleted]

6.6.14 No additional financial penalty may be imposed in respect of a breach of the *market rules* for which a financial penalty has already been imposed pursuant to this section 6.6 provided that nothing in this section 6.6.14 shall prevent the *IESO* from imposing a financial penalty for failure by a *market participant* to remedy a breach in respect of which a financial penalty has been imposed or if there is any repetition or continuation of such breach.

6.7 Officers and Agents

6.7.1 If any director, officer, employee partner or agent of a *market participant* does any act or refrains from doing any act which if done or omitted to be done, as the case may be, by a *market participant* would constitute a breach of the *market rules*, such act or omission shall be deemed for the purposes of this section 6 to be the act or omission of the *market participant*.

7. Financial Penalties for Certain Contracted Ancillary Service Providers

7.1 Penalties Specified in Contracts

7.1.1 An *ancillary service provider* providing *regulation* or *black start capability* under a *contracted ancillary service* contract that:

7.1.1.1 breaches any performance standard set forth in the *market rules*; or

7.1.1.2 fails to pass a test set forth in the *market rules*, the *contracted ancillary service* contract or, where applicable, the *Ontario power system restoration plan*,

in respect of such *contracted ancillary service* shall be subject to such financial penalties and other *sanctions* as may be specified in the applicable *contracted ancillary service* contract and to the provisions of section 4.10.2.1 of Chapter 5.

Exhibit "M"

Chapter 7 of the IESO Market Rules issued November 29, 2023

Exhibit "M"

to the Affidavit of Robin Doolittle

Sworn before me on October 29, 2025, in accordance with O. Reg. 431/20,
Administering Oath or Declaration Remotely



_____

Commissioner for Taking Affidavits
(or as may be)

October 29, 2025

Keith Edward Hickey, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.

Expires June 24, 2027.

Market Rules

Chapter 7
System Operations and Physical Markets

Public

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1. Introductory Rules

1.1 Purpose

1.1.1 This Chapter sets forth rules governing the real-time operations of the *electricity system*, and the market-clearing and pricing process in the *physical markets*.

1.2 Application

1.2.1 The rules in this Chapter apply to:

1.2.1.1 the *IESO*;

1.2.1.2 any person who causes or permits electricity or any *physical service* to be conveyed into, through or out of the *integrated power system*;

1.2.1.3 any registered market participant that submits dispatch data with respect to any registered facility; and

1.2.1.4 transmitters.

1.2.2 The rules in this Chapter apply to both the 60 Hz and the 25 Hz portions of the *electricity system*.

1.2.3 In this Chapter, a reference to the term "area" in the context of *operating reserve* shall be construed as a reference to a portion of the *IESO control area* designated as such by the *IESO* and within which the *IESO* may impose limits on the amount of *ten-minute operating reserve* that can be scheduled from *registered facilities* located within that portion for the purpose of meeting the total requirement for *ten-minute operating reserve* within the *IESO control area*.

1.3 Scope of the Physical Markets

1.3.1 The *IESO* shall administer two types of *physical markets*: the *real-time markets* and the *procurement markets*.

1.3.2 The *IESO* shall administer, in accordance with sections 3 to 8 the following *real-time markets* in an integrated fashion:

1.3.2.1 a market in *energy*, measured in MWh; and

1.3.2.2 a market in several classes of *operating reserve*, measured in MW.

1.3.2.3 [Intentionally left blank- section deleted]

1.3.3 The *IESO* shall administer, in accordance with section 9, the following *procurement markets* to procure certain *physical services* required for *reliable* operation of the *electricity system*:

1.3.3.1 markets for contracted ancillary services, including regulation, reactive support service and voltage control service, and black-start capability; and

1.3.3.2 a market for reliability must-run contracts.

1.4 Co-ordination with Control Areas Outside the IESO Control Area

1.4.1 The *IESO* shall, where required or appropriate under duly constituted regional *reliability* agreements with one or more other *control areas*, and subject to any confidentiality agreements entered into with *market participants* or as part of such *reliability* agreements, share with other *control area operators* all relevant information concerning physical system operations in relation to the *electricity system*.

1.5 Delivery in Respect of Extra-provincial Intertie Transactions

1.5.1 Where *energy* or an *ancillary service* is being conveyed:

1.5.1.1 into the *IESO-controlled grid* from an *intertie zone* outside the Province of Ontario; or

1.5.1.2 out of the *IESO-controlled grid* to an *intertie zone* outside the Province of Ontario,

delivery of such *energy* or *ancillary service* to or from, as the case may be, the *boundary entity* shall, for all purposes under these *market rules*, be deemed to occur on the Ontario portion of the applicable *intertie*.

1.6 Planned Outages for Maintenance and Upgrades of IESO-Administered Markets Software, Hardware and Communication Systems

1.6.1 The *IESO* may, from time to time, undertake *planned outages* on *IESO-administered markets* software, hardware or communication systems for the purpose of maintenance and/or upgrades to those systems. These *planned outages* may result in temporary disruptions to some market activities, including but not limited to submission of *dispatch data*, scheduling, pricing, issuing of *dispatch instructions* and *IESO* report *publishing*.

1.6.2 The *IESO* shall, in respect of a *planned outage* referred to in section 1.6.1:

1.6.2.1 Notify all *market participants*, as far in advance as reasonably practicable, of the timing and duration of the *planned outage*;

1.6.2.2 Maintain normal market operations during the *planned outage* to the greatest extent practicable; and

1.6.2.3 Limit the impact and duration of the *planned outage*, and any resulting disruption to market operations to the greatest extent practicable.

1.6.3 If a *planned outage* referred to in section 1.6.1 is expected to result in a disruption to normal market operations, the *IESO* shall notify all *market participants* of the expected disruption and shall specify any required alternative procedures that will be in effect for the duration of the disruption. These alternative procedures shall be designed so as to permit normal market operations to the greatest extent practicable. These alternative procedures may include, but are not limited to:

1.6.3.1 Submission of *dispatch data* by an alternate means and/or in an alternative form pursuant to section 3.2.2; and

1.6.3.2 Establishment of *administrative prices* pursuant to section 8.4A.

1.6.4 *Market participants* shall comply with the alternative procedures specified by the *IESO* in section 1.6.3.

1.7 IESO Authorities and Obligations Regarding the Operation of the Day-Ahead Commitment Process Functions

1.7.1 The Chief Executive Officer of the *IESO* shall determine when the day-ahead commitment process shall first be used.

1.7.2 [Intentionally left blank – section deleted]

1.7.3 The *IESO* shall notify *market participants* at least five *business days* in advance of the day the day-ahead commitment process will first be used.

1.7.4 The *IESO* shall cancel the day-ahead commitment process for a given *dispatch day* when process or software failures prevent one or more hourly day-ahead commitment process runs from meeting the minimum criteria for a minimum acceptable DACP run, as defined in the applicable *market manual.*

1.7.5 In accordance with the applicable *market manual*, if the *IESO* cancels the day-ahead commitment process for a given *dispatch day*, the *IESO* shall:

- inform *market participants* of the cancellation;
- inform *market participants* as to whether the day-ahead commitment process will resume for the subsequent *dispatch day*.

2. Registration for Physical Operations

2.1 Requirements for Operating on the Grid

2.1.1 No person shall participate in the *real-time markets* or cause or permit electricity or any *physical service* to be conveyed into, through or out of the *integrated power system* unless:

2.1.1.1 that person is authorised to be a *market participant* in accordance with Chapter 2;

2.1.1.2 the *facility* to or from which the electricity or *physical service* is to be so conveyed or the *boundary entity* to which the electricity or *physical service* relates has either been registered by the *IESO* as a *registered facility* pursuant to section 2.2 or section 2.2A, as the case may be, or is exempt from registration under section 2.1.3; and

2.1.1.3 subject to section 2.1.1A, where such *registered facility* is a *generation facility* that is connected electrically to a neighbouring *control area,* and the electricity or *physical service* is to be conveyed out of the *integrated power system* over a *radial intertie*:

a. the person complies with the requirements of Appendix 7.7;

b. the person has entered into a *connection agreement;*

c. the *IESO* has entered into an *interconnection agreement* with the *control area operator, security coordinator* or *interconnected transmitter* for the relevant *radial intertie;* and

d. the *interconnection agreement* referred to in section 2.1.1.3(c) supports the implementation of the requirements of Appendix 7.7.

2.1.1A Section 2.1.1.3 shall not apply in respect of:

2.1.1A.1 the delivery of electricity or a *physical service* out of the *integrated power system* over a *radial intertie* where such delivery is required to provide support in the case of an *emergency* in a *control area*;

2.1.1A.2 the delivery of electricity or a *physical service* out of the *integrated power system* over a *radial intertie* where such delivery is required to provide support in the case of an *outage* in a *control area*; or

2.1.1A.3 the delivery of electricity or a *physical service* out of the *integrated power system* over an *intertie* that is configured as a *radial intertie* following and as a result of a *contingency event.*

2.1.2 A *market participant* shall not submit, and the *IESO* shall not accept, any *dispatch data* with respect to a *facility* or *boundary entity* unless:

2.1.2.1 that facility or boundary entity is a registered facility for the provision of the physical service(s) to which the dispatch data relate;

2.1.2.2 that market participant is the registered market participant for that registered facility; and

2.1.2.3 the *dispatch data* are consistent with: (i) the registration information defining the capabilities of the *registered facility*; (ii) the *market participant's* reasonable expectations of the current actual capabilities of the *registered facility*; and (iii) any revision in registration information requested by the *IESO* under section 7.5.6.2 or other provision of these *market rules*.

2.1.3 Subject to sections 2.3 and 10.2.6, no person that intends to participate in the *IESO-administered markets* or to cause or permit *electricity* or any *physical service* to be conveyed into, through or out of the *integrated power system* shall be required to register the *facility* to or from which the *electricity* or *physical service* is to be so conveyed as a *registered facility* if such *facility* is embedded within a *distribution system*, a load *facility,* a *generation facility* or an *electricity storage facility* and that:

2.1.3.1 in the case of a *generation facility*, has a maximum rated *generation capacity,* net of auxiliary requirements, of less than 1 MW;

2.1.3.2 in the case of a *load facility*, has a maximum load capacity of less than 1 MW;

2.1.3.3 in the case of a *distribution system*, has a maximum load capacity of less than 1 MW; or

2.1.3.4 in the case of an *electricity storage facility*, has a maximum capacity for *energy* for each of injections and withdrawals*,* net of auxiliary requirements, of less than 1 MW.

2.2 Registered Facilities

2.2.1 The *IESO* shall establish a process for registering a *facility* or *boundary entity* as a *registered facility* and for registering a *market participant* as a *registered market participant*. Such process shall include, but not be limited to, the certifications referred to in sections 2.2.3.3 and 2.2.3.4 and the testing and inspection referred to in section 2.2.3.5.

2.2.1A [Intentionally left blank – section deleted]

2.2.2 A market participant may apply to register a facility or boundary entity as a registered facility:

2.2.2.1 for the delivery or withdrawal of specific *physical services* pursuant to the provisions of this section 2.2.

2.2.2.2 [Intentionally left blank – section deleted]

2.2.3 The *IESO* shall approve an application for registration of a *facility* or *boundary entity* as a *registered facility* if:

2.2.3.1 the applying *market participant* submits:

a. the registration information required by this section 2.2;

b. in the case of a *facility connected* to the *IESO-controlled grid*, a copy of the *connection agreement* pertaining to the *facility* and entered into with the applicable *transmitter*; and

c. in the case of a *generation facility,* an *electricity storage facility*, or a *dispatchable load facility* embedded within a *distribution system*, a copy of the *connection agreement* pertaining to the *facility* and entered into with the applicable *distributor*;

2.2.3.2 the *IESO* is satisfied on reasonable grounds that the *facility* is capable of operating as described in the registration information or as otherwise provided by the *market rules* in respect of the relevant *physical service*;

2.2.3.3 the applying *market participant* certifies to the *IESO* that all of the facilities and equipment to which its application for registration relates comply with all applicable technical requirements, other than those referred to in section 6.2 of Chapter 2, set forth in these *market rules* applicable to all *market participants*, the class of *market participant* of which the applying *market participant* forms part and the *IESO-administered market* in which the applying *market participant* wishes to participate;

2.2.3.4 the applying *market participant* certifies to the *IESO* that it has adequate qualified employees or other personnel and organizational and other arrangements that are sufficient to enable the applying *market participant* to perform all of the functions and obligations applicable to *market participants*, the class of *market participant* of which the applying *market participant* forms part and the *IESO-administered market* in which the applying *market participant* wishes to participate in respect of all of the facilities and equipment to which its application for registration relates;

2.2.3.5 the applying *market participant* successfully completes such testing and permits such inspection as the *IESO* may require for the purposes of testing or inspecting whether all of the facilities and equipment to which its application for registration relates meet all applicable technical requirements, other than those referred to in section 6.2 of Chapter 2, set forth in these *market rules* applicable to all *market participants*, the class of *market participant* of which the applying *market participant* forms part and the *IESO-administered market* in which the applying *market participant* wishes to participate;

2.2.3.6 the applying *market participant* certifies to the *IESO* in writing that all of the *facilities* and equipment to which its application for registration relates complies with the requirements identified in any applicable *preliminary assessment* or *system impact assessment* associated with that *market participant's facilities* or equipment; and

2.2.3.7 the applying *market participant* certifies to the *IESO* that all of the *facilities* and equipment to which its application for registration relates does not differ materially from the configuration or technical parameters that were used by the *IESO* as the basis for which it issued any applicable approvals for such new or modified *connection* in accordance with section 6.1.14 to 6.1.18 of Chapter 4, unless the applicable *market participant* or *connection applicant* has obtained the approval of the *IESO* for the change in configuration or technical parameter in accordance with section 6.1.22 of Chapter 4.

2.2.3.8 [Intentionally left blank – section deleted]

2.2.3A [Intentionally left blank – section deleted]

2.2.3B [Intentionally left blank – section deleted]

2.2.4 The *market participant* designated in the registration information as the *market participant* authorised to submit *dispatch data* with respect to a *registered facility* shall be the *registered market participant* for that *registered facility*. The *registered market participant* designated for a *registered facility* may not be changed without the prior approval of the *IESO*.

2.2.5 The *IESO* shall define the form and content of information required for registration as a *registered facility* in accordance with sections 2.2.6 to 2.2.8.

2.2.6 Where the *facility* sought to be registered is within the *IESO control area*, the information required for registration as a *registered facility* shall, subject to any lesser requirements that may be *published* by the *IESO* in respect of the information required for registration of a given class or size of *facility*, include, but not be limited to:

2.2.6.1 the identity of the owner and the operator of the *facility*;

2.2.6.2 the identity of the *market participant* authorised to submit *dispatch data* with respect to the *facility*;

2.2.6.3 for a *connected facility*, information demonstrating that the *facility* has met the *connection* requirements set forth in Chapter 4;

2.2.6.4 information demonstrating that the *market participant* designated as the *registered market participant* for the *facility* has the operational control necessary to assure delivery or withdrawal of the relevant *physical services* as described in the registration information;

2.2.6.5 for a *connected facility*, the location of the *facility* and the identity of the *primary RWM* that will measure the flow of *energy* between the *facility* and the *IESO-controlled grid*;

2.2.6.6 for a *facility* embedded within a *distribution system* or within a *connected facility* within the *IESO control area* that is *connected* to the *IESO-controlled grid*, the location of that *facility*, the identity of the *primary RWM(s)* through which *energy* will flow between that *facility* and the *IESO-controlled grid* and information demonstrating that *energy* can flow to and from the identified *primary RWM*(s) with allocations and loss factors specified in the registration information;

2.2.6.7 standing technical data defining the ability of the *facility* to deliver or withdraw each *physical service* for which registration is sought including, where relevant, the trade-off functions among *energy* and *operating reserves;*

2.2.6.8 for a *facility* that will be subject to the *IESO's dispatch instructions*, certification that the *facility* has a minimum rated *generation capacity*, net of auxiliary requirements, or a minimum *dispatchable load* capacity, of 1 MW, or for an *electricity storage facility* an ability to inject a minimum of 1 MW and withdraw a minimum of 1 MW. Individual *facilities* or units may be aggregated to meet this minimum capacity requirement if they meet the aggregation requirements of section 2.3; and

2.2.6.9 [Intentionally left blank – section deleted]

2.2.6.10 for a cogeneration facility or enhanced combined cycle facility choosing to be either a dispatchable or self-scheduling generation facility, and the registered market participant wishes the compliance bands used to determine whether or not the facility is in compliance with its dispatch instructions or its current schedule, information as outlined in the applicable market manual

concerning the impact that the production or supply of the other forms of useful energy within the facility has on energy production. The IESO may audit this information, which is to be used to determine appropriate compliance bands as outlined in section 3.3.8, at any time.

2.2.6A A *registered market participant* for a *generation facility* may submit the following *facility* specific information: forbidden regions; and period of steady operation. If the information regarding forbidden regions is submitted, the *market participant* shall respect such information when submitting *dispatch data* for the *real-time market*. If the *dispatch data* submitted does not respect such information the *IESO* shall reject the *dispatch data* submission for the affected resource and for the corresponding *dispatch hour* or *dispatch hours* and shall advise the submitting *registered market participant* accordingly.

2.2.6B A *registered market participant* for a *dispatchable generation facility* shall submit to the *IESO* the *minimum loading point*, the *minimum generation block run-time*, and the *minimum run-time* for the *generation facility* if the *minimum loading point* for the *facility* is greater than zero MW and if the *minimum generation block run-time* for the *facility* is greater than one hour.

2.2.6B.1 [Intentionally left blank – section deleted]

2.2.6B.2 [Intentionally left blank – section deleted]

2.2.6B.3 [Intentionally left blank – section deleted]

2.2.6C [Intentionally left blank – section deleted]

2.2.6D The *IESO* may request, and the *registered market participant* for a *dispatchable generation facility* or a dispatchable *electricity storage facility* shall submit to the *IESO*, the following information for that *facility*:

- *start-up time*; and
- *minimum shut-down time*.

2.2.6E If no *facility* specific data is submitted to the *IESO* for the *generation facility's minimum loading point*, *forbidden regions*, or *period of steady operation* in accordance with sections 2.2.6A, and 2.2.6B, the *IESO* shall assign default values of zero for that data.

2.2.6F If *facility* specific data is submitted to the *IESO* in accordance with sections 2.2.6A, 2.2.6B, 2.2.6G or 2.2.6J the *IESO* shall respect the data as submitted in its

determination of the *real-time schedule* in accordance with section 6 and day-ahead schedule in accordance with section 5.

2.2.6G In accordance with the applicable *market manuals*, a *registered market participant* that operates a combined cycle facility that is not aggregated under section 2.3 shall submit to the *IESO* the required data for that combined cycle facility, and for those *registered market participants* that wish to designate their non-aggregated combined cycle *facility* as a *pseudo-unit* in the day-ahead commitment process set out in section 5.8, the required data for that *pseudo-unit*.

2.2.6H A *registered market participant* for a *dispatchable* hydroelectric *generation facility* shall submit to the *IESO* where applicable the *daily cascading* hydroelectric dependency for that *generation facility*.

2.2.6I Subject to section 2.2.6G, the *IESO* shall determine, in accordance with the applicable *market manual*, the *pseudo-unit* technical parameters based on the *facility* specific data submitted under section 2.2.6J.

2.2.6J A *registered market participant* for a *dispatchable generation facility* that is not a quick-start facility may submit on a daily basis the *minimum loading point*, the *minimum generation block run-time*, the maximum number of starts per day and the *minimum generation block down time*, and, for facilities designated as a *pseudo-unit* under section 2.2.6G, the combustion turbine single cycle mode, and the *IESO* shall use this data in the day-ahead commitment process set out in section 5.8.

2.2.6K A *registered market participant* for a *dispatchable generation facility* shall submit to the *IESO* the elapsed time to *dispatch* for the *generation facility*.

2.2.7 Where a *boundary entity* is sought to be registered, a valid *interconnection agreement* over the relevant *interconnection* must have been entered into prior to the approval of the application. In addition, the information required for registration of the *boundary entity* as a *registered facility* shall include, but not be limited to:

2.2.7.1 identification of the *intertie RWM*(s) through which the *physical services* will be delivered to or withdrawn from the *IESO-controlled grid*, which shall determine the *intertie zone* within which the *boundary entity* is deemed to be located;

2.2.7.2 information confirming that the *market participant* authorized to submit *dispatch data* with respect to the *boundary entity* holds all licences, permits or other authorizations that may be required to permit such *market participant* to deliver or withdraw the *physical*

services to or from the *intertie zone* within which the *boundary entity* is deemed to be located;

2.2.7.3 information demonstrating compliance with applicable requirements of all relevant *standards authorities* and completion of the necessary transmission service arrangements with affected *control areas*;

2.2.7.4 the identity of the *market participant* authorized to submit *dispatch data* with respect to the *boundary entity*; and

2.2.7.5 information defining the maximum quantities of each *physical service* that the *market participant* authorized to submit *dispatch data* in respect of the *boundary entity* is entitled to inject into or withdraw from the *IESO-controlled grid* in respect of the *boundary entity* including, where relevant, the trade-off functions among *energy* and *operating reserves.*

2.2.8 In addition to the information required by section 2.2.6 or 2.2.7, as the case may be, the registration information for a *facility* or *boundary entity* that will provide *operating reserves* shall include information in a form approved by the *IESO* demonstrating in the case of a *facility*, the ability of the *facility* or, in the case of a *boundary entity*, the ability of the resources comprising the *boundary entity*, to:

2.2.8.1 provide *energy* and *operating reserves* according to the trade-off functions described in, and with the response times indicated in, the registration information; and

2.2.8.2 deliver, when the *facility* or *boundary entity* is called upon to do so by the *IESO*, *energy* at the specified rate (in MWh/hour or MW) in accordance with its *operating reserve offer* for at least one hour.

2.2.9 A *market participant* may apply to *register* as a *self-scheduling generation facility* any *generation facility*:

2.2.9.1 with a name-plate rating of 1 MW or more but less than 10 MW;

2.2.9.2 that is a *commissioning generation facility* of any name-plate rating and that is sought to be registered pursuant to section 2.2A.1; or

2.2.9.3 that is a *cogeneration facility* or *enhanced combined cycle facility* with a name plate rating of 10 MW or more provided that the *IESO* determines that there are no adverse impacts on the *reliable*

operation of the *IESO-controlled grid* of the *facility* being registered as a *self-scheduling generation facility*.

2.2.9A Except as the *IESO* may authorize under section 21.3.2, a *market participant* may apply to register a *facility* as a *self-scheduling electricity storage facility* only if it:

2.2.9A.1 has an *electricity storage facility size* of 1 MW or more but less than 10 MW and meets the condition of section 2.1.3.4; or

2.2.9A.2 is a *commissioning electricity storage facility* of any capacity and that is sought to be registered pursuant to section 2.2D.

2.2.10 A *self-scheduling generation facility* may be registered:

- to provide *energy* and *reactive support service* and *voltage control service*; and
- as a *certified black start facility*.

2.2.11 The *IESO* shall approve an application for registration as a *self-scheduling generation facility* or a *self-scheduling electricity storage facility* if the information required by this section 2.2 is provided and the *IESO* determines that *self-scheduling* of the *facility* will not have a material adverse effect on power system *security*.

2.2.12 A *self-scheduling generation facility* or a *self-scheduling electricity storage facility* whose application for *facility* registration has been approved by the *IESO* is a *registered facility*.

2.2.13 A *market participant* may apply to register an *intermittent generator* if it has a name-plate rating of not less than 1 MW.

2.2.14 An *intermittent generator* may not be registered to provide any physical service other than *energy* and *reactive support service* and *voltage control service*.

2.2.15 The *IESO* shall approve an application for registration as an *intermittent generator* if the information required by this section 2.2 is provided and the *IESO* determines that intermittent operation of the *facility* will not have a material adverse impact on power system *security*.

2.2.16 An *intermittent generator* whose application for *facility* registration has been approved by the *IESO* is a *registered facility*.

2.2.17 For the purposes of this Chapter, a *distribution system* connected to the *IESO-controlled grid* must be a *registered facility*.

2.2.18 The *IESO* shall develop procedures and requirements for registering a *distribution system* as a *registered facility*. Such procedures shall include, but not be limited to, the certifications referred to in sections 2.2.3.3 and 2.2.3.4 and the testing and inspection referred to in section 2.2.3.5.

2.2.19 A *market participant* may apply to register a *transitional scheduling generator* if it has a nameplate rating of not less than 1MW.

2.2.20 A *transitional scheduling generator* may be registered:

- to provide *energy* and *reactive support service* and *voltage control service* and
- as a *certified black start facility*.

2.2.21 The *IESO* shall approve an application for registration as a *transitional scheduling generator* if the information required by this section 2.2 is provided, and the *generator* is under contract with *OEFC* and will participate in the *real-time market* for *energy*.

2.2.22 A *transitional scheduling generator* whose application for *facility* registration has been approved by the *IESO* is a *registered facility*.

2.2.23 Within one month of the coming into effect of the amendments to the contract with *OEFC* required as a result of electricity industry restructuring in Ontario in respect of a *transitional scheduling generator*, the *registered market participant* for the *transitional scheduling generator* shall change registration for the applicable *generation facility* to one of the other *generation facility* registrations.

2.2.24 [Intentionally left blank – section deleted]

2.2A Registration of Commissioning Generation Facilities

2.2A.1 A *market participant* may apply to register a *commissioning generation facility* as a *self-scheduling generation facility*, in accordance with section 2.2, for the purpose of being permitted to convey electricity or a *physical service* into, through or out of the *integrated power system* or of participating in the *real-time markets* during the period in which the *commissioning generation facility* is undergoing the commissioning tests referred to in section 2.2A.4.

2.2A.2 The *IESO* shall approve an application for *facility* registration of a *commissioning generation facility* as a *self-scheduling facility* if it is satisfied that the requirements of section 2.2 have been met. Any such registration shall expire upon completion by the *commissioning generation unit* of the final

commissioning test submitted to and approved by the *IESO* pursuant to section 2.2A.4.

2.2A.3 Upon expiry of the registration referred to in section 2.2A.2, a *market participant* shall not participate in the *real-time markets* nor cause or permit electricity or any *physical service* to be conveyed into, through or out of the *integrated power system* in respect of a former *commissioning generation facility* unless such former *commissioning generation facility* has been registered as a *generation facility*, other than pursuant to this section 2.2A, in accordance with section 2.2.

2.2A.4 Where a *commissioning generation facility* has been registered by the *IESO* pursuant to section 2.2A.2, the *market participant* for that *commissioning generation facility* shall, while such registration is in effect:

2.2A.4.1 ensure that the commissioning generation facility:

a. complies with all of the provisions of these *market rules* applicable to *self-scheduling generation facilities*; and

b. where it will seek to be registered, other than pursuant to this section 2.2A, in accordance with section 2.2 as other than a *self-scheduling generation facility*, complies with all of the applicable requirements of section 7.3 of Chapter 4; and

2.2A.4.2 submit to the *IESO*, for approval and in accordance with section 2.2A.5, information detailing the commissioning test plans for the *commissioning generation facility*.

2.2A.5 The detailed commissioning test plans, referred to in section 2.2A.4.2 shall be submitted to the *IESO* for approval and shall be scheduled in accordance with the procedures applicable to the *outage* coordination process described in section 6 of Chapter 5 and with any applicable *market manual* and shall include, but not be limited to:

2.2A.5.1 the time required for the *commissioning generation facility* to synchronize to and de-synchronize from the *IESO-controlled grid*;

2.2A.5.2 *energy* and reactive output levels;

2.2A.5.3 the timing of and ramp rates associated with changes in *energy* and reactive output levels; and

2.2A.5.4 run-back or trip tests for the *commissioning generation facility*.

2.2A.6 Except as otherwise provided in this section 2.2A, where a *commissioning generation facility* has been registered by the *IESO* pursuant to section 2.2A.2, the *IESO* shall, while such registration is in effect, treat the *commissioning generation facility* as a *self-scheduling generation facility* for all purposes under these *market rules* including, but not limited to, the submission of *dispatch data* and *settlement*.

2.2B Generation Facility Eligibility for the Real-Time Generation Cost Guarantee

2.2B.1 A *registered market participant* for a *generation facility* shall be eligible for the guarantee of certain elements of its costs, calculated in accordance with section 4.7B of Chapter 9, provided the following criteria are met:

2.2B.1.1 the facility is not a quick-start facility;

2.2B.1.2 the facility is a dispatchable generation facility; and

2.2B.1.3 [Intentionally left blank – section deleted];

2.2B.1.4 the *registered market participant* has submitted to the *IESO* the following data for the *generation facility*, in accordance with the applicable *market manual*, and the *IESO* accepts the data as reasonable:

2.2B.1.4A the minimum run-time, minimum loading point, and minimum generation block run-time;

2.2B.1.4B the incremental fuel costs and incremental operating and maintenance costs determined in accordance with sections 2.2B.4, 2.2B.5 and 2.2B.6; and

2.2B.1.4C any other data, as reasonably requested by the *IESO* that is relevant to determine eligible costs in accordance with section 2.2B.4, from the *registered market participant*, any *affiliate*, service provider or contractual counter-party.

2.2B.2 The *IESO* may, at any time, audit the data submitted in accordance with section 2.2B.1.4, and the *registered market participant* shall provide the requested audit information in the time and manner specified by the *IESO*. If, as a result of such an audit, the *IESO* determines that the audit information provided does not support the submitted data, including, without limitation, that the *IESO* does not accept the data as reasonable, the *IESO* shall recover any resulting over-payments made to the *market participant.* Notwithstanding the foregoing sentence, where the *registered market participant* has submitted data in accordance with this section 2.2B and sections 10A.1 and 11.2.1 of Chapter 1, the *IESO* shall not retroactively revise pre-approved cost values determined in accordance with

section 2.2B.5 when calculating any amount to be recovered from that *registered market participant*.

2.2B.3 For purposes of sections 2.2B.1.4 and 2.2B.2, the *registered market participant* shall retain supporting documentation related to cost submissions, including data that may be required by the *IESO* to determine pre-approved cost values and methodologies, in accordance with the applicable *market manual*, for a period of 7 years from the date when a cost is paid.

Submitted Eligible Costs

2.2B.4 Submitted eligible costs pursuant to section 2.2B.1 shall be limited to:

2.2B.4.1 incremental fuel costs, incremental operating and maintenance costs resulting from *wear and tear* caused by the operation of a *facility*; and

2.2B.4.2 all other incremental operating and maintenance costs as set out in section 4.7B.5.2 of Chapter 9;

from either the point of ignition or synchronization to the *IESO-controlled grid* as applicable, until the *facility* reaches its *minimum loading point*, where that *facility* has met the eligibility criteria specified in sections 2.2B.1, 5.7 and 6.3A, as specified and further detailed in the applicable *market manual*.

2.2B.5 Subject to section 2.2B.6, for each cost specified in section 2.2B.4, the *IESO* shall determine pre-approved cost values and methodologies that are either universal or *facility*-specific, and calculate the submitted eligible costs in accordance with section 4.7B.5 of Chapter 9. The pre-approved cost values and methodologies shall remain in effect until revised by the *IESO*. The *IESO* shall review the pre-approved cost values and methodologies at least once every 3 years. The first review shall be completed no later than 3 years from the effective date of this section.

2.2B.6 In circumstances where pre-approved cost values and methodologies are not established under section 2.2B.5, the *IESO* may at its sole discretion allow a *registered market participant* to submit the incremental fuel costs and incremental operating and maintenance costs for each *facility* under section 2.2B.1.4B, in accordance with the applicable *market manual*.

2.2C Generation Facility Eligibility for the Day-Ahead Production Cost Guarantee

2.2C.1 A *registered market participant* for a *generation facility* shall be eligible for the guarantee of certain elements of the *facility's* costs, calculated in accordance with section 4.7D of Chapter 9, provided the following criteria are met:

2.2C.1.1 the facility is not a quick-start facility;

2.2C.1.2 the *facility* is a *dispatchable generation facility* with a elapsed time to *dispatch* greater than one hour;

2.2C.1.3 [Intentionally left blank – section deleted];

2.2C.1.4 the *registered market participant* has, according to the timelines and in the form specified in the applicable *market manual*, submitted to the *IESO* the following information for the *generation facility*: the start-up costs; and the speed no-load costs; and

2.2C1.5 the *registered market participant* has, according to the timelines and in the form specified in the applicable *market manual*, submitted to the *IESO* the following information for the *generation facility*: the *minimum loading point*; and the *minimum generation block run-time* and the *IESO* accepts all such information as reasonable.

2.2C.2 [Intentionally left blank – section deleted]

2.2D Registration of Commissioning Electricity Storage Facilities

2.2D.1 A *market participant* may apply to register a *commissioning electricity storage facility* as a *self-scheduling electricity storage facility*, in accordance with section 2.2, for the purpose of being permitted to convey electricity or a *physical service* into, through or out of the *integrated power system* or of participating in the *real-time markets* during the period in which the *commissioning electricity storage facility* is undergoing the commissioning tests referred to in section 2.2D.4.

2.2D.2 The *IESO* shall approve an application for *facility* registration of a *commissioning electricity storage facility* as a *self-scheduling facility* if it is satisfied that the requirements of section 2.2 have been met. Any such registration shall expire upon completion by the *commissioning electricity storage unit* of the final

commissioning test submitted to and approved by the *IESO* pursuant to section 2.2D.4.

2.2D.3 Upon expiry of the registration referred to in section 2.2D.2, a *market participant* shall not participate in the *real-time markets* nor cause or permit electricity or any *physical service* to be conveyed into, through or out of the *integrated power system* in respect of a former *commissioning electricity storage facility* unless such former *commissioning electricity storage facility* has been registered as an *electricity storage facility*, other than pursuant to this section 2.2D, in accordance with section 2.2.

2.2D.4 Where a *commissioning electricity storage facility* has been registered by the *IESO* pursuant to section 2.2D.2, the *market participant* for that *commissioning electricity storage facility* shall, while such registration is in effect:

2.2D.4.1 ensure that the commissioning electricity storage facility:

a. complies with all of the provisions of these *market rules* applicable to *self-scheduling electricity storage facilities*; and

b. where it will seek to be registered, other than pursuant to this section 2.2D, in accordance with section 2.2 as other than a *self-scheduling electricity storage facility*, complies with all of the applicable requirements of section 7.3 of Chapter 4; and

2.2D.4.2 submit to the *IESO*, for approval and in accordance with section 2.2D.5, information detailing the commissioning test plans for the *commissioning electricity storage facility*.

2.2D.5 The detailed commissioning test plans, referred to in section 2.2D.4.2 shall be submitted to the *IESO* for approval and shall be scheduled in accordance with the procedures applicable to the *outage* coordination process described in section 6 of Chapter 5 and with any applicable *market manual* and shall include, but not be limited to:

2.2D.5.1 the time required for the *commissioning electricity storage facility* to synchronize to and de-synchronize from the *IESO-controlled grid*;

2.2D.5.2 *energy* and reactive output levels;

2.2D.5.3 the timing of and ramp rates associated with changes in *energy* and reactive output levels; and

2.2D.5.4 run-back or trip tests for the commissioning electricity storage facility.

2.2D.6 Except as otherwise provided in this section 2.2D, where a *commissioning electricity storage facility* has been registered by the *IESO* pursuant to section 2.2D.2, the *IESO* shall, while such registration is in effect, treat the *commissioning electricity storage facility* as a *self-scheduling electricity storage facility* for all purposes under these *market rules* including, but not limited to, the submission of *dispatch data* and *settlement*.

2.3 Aggregated Registered Facilities

2.3.1 A *market participant* may apply to the *IESO* to aggregate several *facilities* for the purpose of delivering or withdrawing one or more *physical services* in the *real-time energy market*, the *procurement markets* or both. Upon *IESO* approval, the aggregated *facilities* shall, except as specifically stated in the registration information or the *IESO*'s approval of the aggregation, be treated as a single *registered facility* for the provision or withdrawal of the approved *physical services*:

2.3.1.1 by the *registered market participant* for purposes of the submission of *dispatch data*; and

2.3.1.2 by the *IESO*, for purposes of the scheduling and *dispatch* processes described in this Chapter.

2.3.1A [Intentionally left blank – section deleted]

2.3.1A.1 [Intentionally left blank – section deleted]

2.3.1A.2 [Intentionally left blank – section deleted]

2.3.2 The *IESO* shall approve an application for the aggregation of *facilities* into a single *registered facility* unless:

2.3.2.1 the registration information for the *facilities* proposed to be aggregated fails to satisfy the conditions of section 2.2;

2.3.2.2 the registration information fails to demonstrate one or more of the following in respect of the *facilities* proposed to be aggregated;

a. that they are all located within the *IESO control area*;

b. subject to section 2.3.2A, that they are all *connected* to the *IESO-controlled grid* at the same *connection point*;

c. that they are all under the operational control of a single *market participant* and that such *market participant* is authorized to submit *dispatch data* for all of them;

d. that operational communication between each of them and the *IESO* meets all applicable standards and protocols; or

e. that they all have relevant metering systems to be used for *settlements* purposes that satisfy the requirements of Chapter 6; or

2.3.2.3 one or more of the facilities proposed to be aggregated is or includes a *generation unit*, an *electricity storage unit*, or a *load facility* :

a. whose *offer* or *bid* information or whose in service or out of service status affects the numerical value of operating *security limits* in any manner;

b. whose *offer* or *bid* information or whose in service or out of service status is information required by the *IESO* for conducting detailed *security* and resource adequacy assessment;

c. whose *offer* or *bid* information or whose in service or out of service status is information required to be submitted to the *market assessment unit* or the *market surveillance panel* in furtherance of their respective functions and obligations under the *Electricity Act, 1998* the *Ontario Energy Board Act, 1998* and these *market rules*; or

d. whose *offer* or *bid* information, in service or out of service status or other information is required by *applicable law*, by *license*, by the *Ontario Energy Board* or by a *standards authority* to be submitted to or obtained by the *IESO*.

2.3.2.4 the applying *market participant* fails to provide the certification referred to in section 2.2.3.3 in respect of any of the *facilities*;

2.3.2.5 the applying *market participant* fails to provide the certification referred to in section 2.2.3.4 in respect of any of the *facilities*; or

2.3.2.6 the applying *market participant* fails to successfully complete the testing or to permit the inspection referred to in section 2.2.3.5 in respect of any of the *facilities.*

2.3.2A Notwithstanding section 2.3.2.2b, the *IESO* may approve an application for the aggregation of *facilities* into a single *registered facility* that are not all *connected* to the *IESO-controlled grid* at the same *connection point*, provided that, in the sole judgement of the *IESO*, they can be represented as a single point of injection or withdrawal without compromising the *reliability* of the *IESO-controlled grid*. Aggregation for the purposes of calculating *transmission service charges* is specified in the then current *Ontario Energy Board* Transmission Rate Order.

2.3.3 If a proposed aggregation of *facilities* meets one or more of the above conditions, the *IESO:*

2.3.3.1 shall provide to the *market participant* whose application is denied the reasons for such denial.

2.3.3.2 [Intentionally left blank]

2.3.3.3 [Intentionally left blank]

2.3.4 Approval of the aggregation of *facilities* shall be withdrawn by the *IESO* where, for any reason, one or more of the aggregation *facilities* commences to meet any one or more of the conditions described in section 2.3.2. The *IESO* shall give notice of the withdrawal to the *market participant* authorized to submit *dispatch data* in respect of the aggregated *facilities* and shall cease to treat those *facilities* as a single *registered facility* as of the date and time specified in the notice for such purpose. The date and time so specified shall not be less than 2 days from the date and time at which the notice of withdrawal is given to the *market participant*. If the *market participant* subsequently wishes to thereafter re-aggregate the *facilities*, it shall be required to re-apply to the *IESO* for approval of the aggregation in accordance with section 2.3.1.

2.3.5 A *market participant* authorized to submit *dispatch data* for aggregated *facilities* may give notice to the *IESO* that it no longer wishes to aggregate those *facilities*. The *IESO* shall acknowledge receipt of the *market participant's* notice and shall cease to treat those *facilities* as a single *registered facility* as of the date and time specified in the acknowledgement of receipt for that purpose. The date and time so specified shall be as soon as reasonably practicable following the date of receipt by the *IESO* of the *market participant's* notice. If the *market participant* subsequently wishes to re-aggregate the *facilities*, it shall be required to re-apply to the *IESO* for approval of the aggregation in accordance with section 2.3.1.

2.4 De-registration of Facilities

2.4.1 A *market participant* that wishes to de-register a *registered facility*, other than a *boundary entity*, which is being removed from service shall file with the *IESO* a notice of request to de-register in such form as may be specified by the *IESO;* provided, however, that a *market participant* shall not be entitled to file such a notice if it is no longer the beneficial owner of the *registered facility*.

2.4.2 Within ten *business days* of the date of receipt of the notice referred to in section 2.4.1, the *IESO* shall notify the *market participant* and the *transmitter* to whose *transmission system* the *registered facility* is *connected* as to whether the *IESO* requires a technical assessment of the impact of the removal from service of the *registered facility* on the *reliability* of the *IESO-controlled grid* and, if so, of the expected date of completion of such assessment. Such date shall not be more than 45 days from the date of issuance by the *IESO* of such notice or such later date as may be agreed between the *IESO* and the *market participant*.

2.4.3 Where the notice issued by the *IESO* pursuant to section 2.4.2 indicates that the *IESO* does not require a technical assessment or where the *IESO* conducts a technical assessment and concludes the removal from service of the *registered facility* will not or is not likely to have an unacceptable impact on the *reliability* of the *IESO-controlled grid*, the *market participant* shall file with the *IESO* a notice setting forth the date upon which the *market participant* wishes the *IESO* to de-register the *registered facility*. Such date shall not be less than five *business days* from the date of receipt by the *market participant* of the notice issued by the *IESO* pursuant to section 2.4.2 and, as applicable, shall be subject to the date on which the *registered facility* has been *disconnected* as confirmed by the relevant *transmitter* to the *IESO*.

2.4.4 Where section 2.4.3 applies, the *IESO* shall:

2.4.4.1 if the *registered facility* is not *connected* to the *IESO-controlled grid*, de-register the *registered facility* promptly upon completion of the technical assessment if applicable, or as of the date specified in the notice filed by the *market participant* pursuant to section 2.4.3, whichever is the later, and shall so notify the *market participant*, the *metering service provider* for the *metering installation* that relates to the *registered facility,* and any *market participant* within which the *registered facility* is embedded; or

2.4.4.2 if the registered facility is connected to the IESO-controlled grid:

a. issue to the relevant *transmitter* a *disconnection order* directing the relevant *transmitter* to *disconnect* the *registered facility* from the *IESO-controlled grid* on the date specified in the *disconnection order* which shall be no earlier than the date specified in the notice filed by the *market participant* pursuant to section 2.4.3; and

b. de-register the *registered facility* as of the date on which the relevant *transmitter* confirms to the *IESO* that the *registered facility* has been *disconnected* from the *IESO-controlled grid*.

and shall notify the *market participant* accordingly.

2.4.5 Where the *IESO* conducts the technical assessment referred to in section 2.4.2 and concludes that the removal from service of the *registered facility* will or is likely to have an unacceptable impact on the *reliability* of the *IESO-controlled grid,* the *IESO* and the *market participant* shall commence the process described in sections 9.6 and 9.7 and in section 4.8 of Chapter 5 with a view to concluding a *reliability must-run contract* for that *registered facility*. The *registered facility* shall not be removed from service during the course of such process.

2.4.6 [Intentionally left blank – section deleted]

2.4.6.1 [Intentionally left blank – section deleted]

2.4.6.2 [Intentionally left blank – section deleted]

2.4.7 A *transmitter* that receives a *disconnection order* from the *IESO* pursuant to section 2.4.4.2(a) shall:

2.4.7.1 subject only to section 3.4.1.5 of Chapter 5 and to the completion of any operating and decommissioning procedures contemplated in the *connection agreement* applicable to the *registered facility*, *disconnect* the *registered facility* from the *IESO-controlled grid* on the date and at the time specified in the *disconnection order*; and

2.4.7.2 promptly inform the *IESO* once the *registered facility* has been *disconnected* from the *IESO-controlled grid.*

Planned Retirements of Generation and Electricity Storage Facilities

2.4.8 Each *generator* shall provide the *IESO* not less than six months advance notice of the commencement of the planned retirement of any one of its *generation facilities* that are *registered facilities*, including notification of any plans the *generator* may have to construct replacement *facilities* for those being retired.

2.4.9 Each *electricity storage participant* shall provide the *IESO* not less than six months advance notice of the commencement of the planned retirement of any one of its *electricity storage facilities* that are *registered facilities*, including notification of any plans the *electricity storage participant* may have to construct replacement *facilities* for those being retired.

2.5 Transfer of Registration of Facilities

2.5.1 A *market participant* that wishes to transfer the registration of a *registered facility*, other than a *boundary entity*, as a result of the proposed transfer of the *registered facility* to another person by sale, assignment, lease, transfer of control or other means of disposition shall, not less than 10 *business days* prior to the date on which the transfer is proposed to take effect, file with the *IESO* and the relevant *transmitter* or *distributor*, a notice of request to transfer the registration of the *registered facility* in such form as may be specified by the *IESO*. Such notice shall specify:

2.5.1.1 the identity of the transferee and whether the transferee is or intends to be a *market participant*; and

2.5.1.2 the date upon which the transfer is proposed to take effect,

and shall be accompanied by a written declaration by the proposed transferee that it is willing and able to assume control of the *registered facility* and to comply with all provisions of these *market rules* and of any *reliability must-run contract* or *contracted ancillary services* contract applicable to such *registered facility.*

2.5.2 If the proposed transferee satisfies or is capable of satisfying the requirements of section 2.2, the *IESO* shall approve a request to transfer the registration of a *registered facility* unless the proposed transferee is a *suspended market participant* or is otherwise ineligible under these *market rules* to be a *market participant*.

2.5.3 Where the *IESO* approves a request to transfer the registration of a *registered facility*, the *IESO* shall transfer the registration of the *registered facility* to the proposed transferee:

2.5.3.1 on the date referred to in section 2.5.1.2, provided that the proposed transferee was a *market participant* at the time of filing of the notice referred to in section 2.5.1 and remains a *market participant* on such date; or

2.5.3.2 on such later date as may reasonably be required to permit the *IESO* to effect the transfer following the later of the date of authorization of the

proposed transferee as a *market participant* and the date on which the proposed transferee meets the requirements of section 2.2.

2.5.4 Upon completion of the transfer of the *registered facility*, the proposed transferee will have to post with the *IESO prudential support* or *capacity prudential support* as applicable, equal to the proposed transferee's *prudential support obligation* or *capacity prudential support obligation*. Until the proposed transferee has done so, the transferring *market participant* shall continue to be liable for the obligations of the proposed transferee in the *IESO-administered markets*. Such obligations shall include, without limitation, the cost of electricity withdrawn from the *IESO-controlled grid* by the proposed transferee and related charges as determined by the *IESO* in accordance with Chapter 9. The *prudential support obligation* and/or *capacity prudential support obligation* as applicable of the transferring *market participant* shall include all such amounts whether or not the transferring *market participant* has complied with the provisions of this section 2.5.

3. Data Submissions for the Real-Time Markets

3.1 Applicability of this Section

3.1.1 A *registered market participant* that intends one or more of its *registered facilities* to be eligible for *dispatch* by the *IESO* for a given *dispatch hour* of a *dispatch day* shall submit to the *IESO dispatch data* for each such *registered facility* for such *dispatch hour* in accordance with this section 3.

3.1.2 *Dispatch data* that are revised after initial submission as allowed under the provisions of this section 3 must satisfy all of the requirements that apply to initial *dispatch data* and shall be *dispatch data*.

3.1.3 [Intentionally left blank – section deleted]

3.2 The Data Submission Process

3.2.1 Each *registered market participant* shall submit its *dispatch data* to the *IESO* through the *electronic information system* or, when not available, by such alternative means and/or in such alternative simplified form as may be specified by the *IESO* pursuant to section 3.2.2.3.

3.2.2 The *IESO* shall:

3.2.2.1 stamp all *dispatch data* with the time that it was received by the *IESO*;

3.2.2.2 within five minutes, confirm receipt of all such *dispatch data* through the *electronic information system*; and

3.2.2.3 specify alternative means and/or an alternative simplified form of submitting and confirming *dispatch data* when the *electronic information system* is unavailable.

3.2.3 The *IESO* shall reject any *dispatch data* that does not comply with the rules set forth in this section 3 and shall provide to the *registered market participant* submitting such rejected *dispatch data* the reasons for such rejection.

3.2.4 A *registered market participant* that does not receive from the *IESO* confirmation of receipt of *dispatch data* in accordance with section 3.2.2.2 shall immediately contact the *IESO* by telephone or facsimile seeking confirmation of receipt.

3.2.5 A *registered market participant* shall, if requested by the *IESO*, resubmit *dispatch data* by such means as may be specified by the *IESO* in the request.

3.3 Dispatch Data Submissions

3.3.1 Subject to sections 3.3.9 and 3.3A, a *registered market participant* that submits or is required to submit *dispatch data* for the initial *pre-dispatch schedule,* shall submit initial *dispatch data* for each *dispatch hour* of the *dispatch day* after 06:00 EST but before 10:00 EST of each *pre-dispatch day.* Such initial *dispatch data* may thereafter be revised as permitted by this section 3.3.

3.3.2 Subject to section 3.3A.6, the *IESO* shall use the initial *dispatch data* submitted by *registered market participants* to determine and *publish* the initial *pre-dispatch schedule* in accordance with section 5.

3.3.3 Subject to section 3.3A.8, a *registered market participant* may submit revised *dispatch data* with respect to any *dispatch hour* without restriction until 2 hours prior to the beginning of that *dispatch hour*.

3.3.4 [Intentionally left blank – section deleted]

3.3.4A [Intentionally left blank – section deleted]

Replacement Energy Offers

3.3.4B A registered market participant for a hydroelectric generation facility, a combined cycle generation facility, an enhanced combined cycle facility or a cogeneration facility that experiences a forced outage may submit revised dispatch data for a related generation facility, with respect to any dispatch hour up until 10 minutes prior to the beginning of that dispatch hour. If the revised dispatch data is submitted less than 10 minutes prior to the beginning of that dispatch hour, the revised dispatch data will apply to the subsequent dispatch hour. This section is subject to the following conditions:

- The submission of revised *dispatch data* takes place no later than one hour after the *generation facility* experiences the *forced outage* and is limited to the MW amount on *forced outage.*
- The *registered market participant* whose *generation facility* experienced a *forced outage* notifies the *IESO,* in accordance with the applicable *market manual*, of its intention to submit revised *dispatch data* for the related *generation facility* for the next available *dispatch hour* and of its intention to provide replacement *energy* from the related *generation facility.*
- Where the related *generation facility* is not synchronized, the *registered market participant* notifies the *IESO* of its intention to synchronize the related *generation facility* and the *IESO* determines synchronization will have no adverse impact on the *reliability* of the *IESO-controlled grid.*
- The related *generation facility* and the *generation facility* experiencing the *forced outage* have the same *registered market participant*.
- The related *generation facility* and the *generation facility* experiencing the *forced outage* have the same *metered market participant*.

Related *generation facilities* are *generation facilities* that, in the case of a hydroelectric *generation facility*, can utilize the water of the *generation facility* experiencing the *forced outage* without delay. In the case of combined cycle *facilities, enhanced combined cycle facilities* or *cogeneration facilities,* related *generation facilities* are *generation facilities* that can make up the loss in steam production to the steam turbine unit that would otherwise have been produced by the gas turbine unit experiencing the *forced outage.*

3.3.4C In the period after the notification and before the market tools process the revised *dispatch data,* the *IESO* shall accept replacement *energy* from the related *generation facility*, provided there is no adverse impact on the *reliability* of the *IESO-controlled grid.* The replacement *energy* delivered shall be limited to the amount of *energy* originally scheduled for the *generating facility* experiencing the *forced outage.* The *market participant* may choose to provide replacement *energy* from a related *generation facility* without submitting revised *dispatch data* for the

current *dispatch hour* or, if within 10 minutes of the next *dispatch hour*, the current and subsequent *dispatch hour*.

3.3.5 Except as permitted by sections 3.3.4B, 3.3.8, 3.3.9.2, 3.3.11, and 21.6 no *registered market participant* may, without the approval of the *IESO*, submit revised *dispatch data* with respect to any *dispatch hour* within 2 hours of that *dispatch hour*.

IESO Approvals of Revised Dispatch Data

3.3.6 Where pursuant to section 3.3.5, the approval of the *IESO* is required for the submission of revised *dispatch data*, the *IESO* shall, unless the change in quantity poses risks in relation to the *reliability* or *security* of the *electricity system*, approve the submission of revised *dispatch data* where:

3.3.6.1 [Intentionally left blank – section deleted]

3.3.6.2 [Intentionally left blank – section deleted]

3.3.6.3 the *registered market participant* indicates, at the time of the submission of the revised *dispatch data*, that the revision is required in order to reflect a proposed change in the operational status of the *registered facility* designed solely to prevent the *registered facility* from operating in a manner that would endanger the safety of any person, damage equipment, or violate any *applicable law*.

The *IESO* may refer such changes or revision of *dispatch data* to the *market surveillance panel*.

3.3.7 *Dispatch data* submitted during the *dispatch day* to which it applies need refer only to the remaining *dispatch hours* of that *dispatch day*.

3.3.8 Notwithstanding any other provision of this section 3.3 and with the exception of testing specified in section 6.6 of Chapter 5, a *registered market participant* shall as soon as practical submit to the *IESO* revised *dispatch data* for any *registered facility* in respect of which it is the *registered market participant* if, for any *dispatch hour* in the current *pre-dispatch schedule,* the quantity of any *physical service* scheduled for that *registered facility* differs from the quantity the *registered market participant* reasonably expects to be delivered or withdrawn by more than the greater of:

(i) 2 percent;

(ii) such absolute amount as may be determined by the *IESO* based on considerations of *reliability* and *facility* specific characteristics;

(iii) in the case of a *cogeneration facility* that is either a *dispatchable* or *self-scheduling generation facility*, such amount based on the impact that the production of the other forms of useful energy within the *facility* has on *energy* production based on the information outlined in section 2.2.6.10, and the *IESO*; and

(iv) in the case of an *enhanced combined cycle facility* that is either a *dispatchable* or *self-scheduling generation facility*, such amount based on the impact that the recovery of waste heat from an industrial process/processes within the *facility* has on *energy* production based on the information outlined in section 2.2.6.10;

and the *IESO*:

3.3.8.1 shall, unless the change in quantity poses risks in relation to the *reliability* or *security* of the *electricity system*, include such change as an input in respect of any subsequent *market schedules* determined following receipt of the change; and

3.3.8.2 may refer such changes or revision of *dispatch data* to the *market surveillance panel*.

Standing Dispatch Data

3.3.9 If the dispatch data for a registered facility for a given trading day of a trading week will not change from trading week to trading week, the registered market participant for that registered facility may, as and for its dispatch data described in section 3.3.1, submit standing dispatch data for that registered facility. Such standing dispatch data shall:

3.3.9.1 define the *dispatch data* for each *dispatch hour* of each *dispatch day*;

3.3.9.1A in respect of each *dispatch day* for which it is in effect, be deemed for the purposes of this section 3.3 to be initial *dispatch data* at 06:00 EST on the *pre-dispatch day*; and

3.3.9.2 remain in effect until the expiration date specified in the standing *dispatch data* unless earlier withdrawn or earlier revised by the *registered market participant*:

a. as standing *dispatch data* prior to 06:00 EST on the *pre-dispatch day*; or

b. in accordance with sections 3.3.3 to 3.3.8.

IESO Authorities to Direct Submission or Revision of Dispatch Data

3.3.10 Notwithstanding sections 3.3.3, 3.3.4, 3.3.4B, 3.3.5 and 3.3.8, where the *IESO* determines, on the basis of the initial *pre-dispatch schedule* or any subsequent *pre-dispatch schedule* determined in accordance with section 5, that a revision to *dispatch data* will not allow it to maintain the *reliability* of the *IESO-controlled grid*, the *IESO* may, subject to sections 3.3.15 and 3.3.16:

3.3.10.1 refuse to accept a revision to the quantity element of *dispatch data* submitted by a *registered market participant*; or

3.3.10.2 direct a *registered market participant* to submit or to resubmit a revision to the quantity element of its *dispatch data*, or both. The *IESO* shall notify the *registered market participant* of a refusal referred to in section 3.3.10.1 and shall include in any direction issued pursuant to section 3.3.10.2 a description of the revised *dispatch data* to be submitted or resubmitted by the *registered market participant*.

3.3.10A A *registered market participant* in respect of a *transitional scheduling generator* may treat a direction referred to in section 3.3.10.2 that means an increase in the quantity element of its *dispatch data* as a request and shall confirm with the *IESO* its intention to comply or not comply with the request issued. If the *registered market participant* indicates its intentions are not to comply with the direction, the *registered market participant* shall provide the reasons for non-compliance to the *IESO*.

3.3.11 A *registered market participant* to which a direction has been issued pursuant to section 3.3.10.2 shall submit revised *dispatch data* to the *IESO* in accordance with the terms of the direction within 2 hours of the time of receipt of the direction.

3.3.12 If the *IESO* determines, on the basis of the initial *pre-dispatch schedule* or any subsequent *pre-dispatch schedule* determined in accordance with section 5, that it requires the supply of *energy, ancillary services*, other than *contracted ancillary services*, or both from additional *registered facilities* in order to maintain the *reliability* of the *IESO-controlled grid*, the *IESO* shall determine if there are additional *registered facilities* that have not submitted *dispatch data* and that can, to the *IESO's* knowledge, be made available within the time required in order to help maintain the *reliability* of the *IESO-controlled grid*.

3.3.13 Subject to sections 3.3.14 to 3.3.16, the *IESO* may direct the *registered market participant* for an additional *registered facility* identified pursuant to section 3.3.12 to submit *dispatch data*, and shall include in such direction a description of the *dispatch data* to be submitted by the *registered market participant*.

3.3.14 A *registered market participant* to which a direction is issued pursuant to section 3.3.13 shall submit *dispatch data* to the *IESO* in accordance with the terms of the direction within 2 hours of the time of receipt of the direction.

3.3.15 The *IESO* shall not issue a direction pursuant to section 3.3.10 or 3.3.13 for the purposes of addressing a lack of overall *adequacy* of the *IESO-controlled grid*.

3.3.16 Where a *registered facility* to which a direction issued pursuant to section 3.3.10.2 or 3.3.13 relates has a *reliability must-run contract* with the *IESO*, any such direction shall, subject to the time period for the submission of *dispatch data* referred to in sections 3.3.11 and 3.3.14, be consistent with the terms of such *reliability must-run contract*.

3.3.17 Nothing in sections 3.3.10 to 3.3.16 shall preclude the application of the provisions of sections 7.3.2.3 or of Appendix 7.6 in respect of *dispatch data* that is revised or submitted in accordance with sections 3.3.10 to 3.3.16.

3.3.18 A *registered market participant* may, for any one or more of its *registered facilities* that is a *dispatchable load*, identify all or a portion of the consumption at such *registered facilities* as *non-dispatchable load* by submitting *dispatch data* in accordance with the applicable *market manual*.

3.3A Dispatch Data Submissions for the Day-Ahead Commitment Process

3.3A.1 Subject to section 1.7, defining when the day-ahead commitment process shall function, this section 3.3A shall be in effect.

3.3A.2 Subject to the standing *dispatch data* provisions of section 3.3.9, each *registered market participant* that intends its *dispatchable generation facility*, including a *generation facility* that intends to operate in *segregated mode of operation* in real-time, *dispatchable load facility*, dispatchable *electricity storage facility*, or *hourly demand response* resource to be eligible for *dispatch* by the *IESO* for a given *dispatch hour* of a *dispatch day* shall, after 06:00 EST but before 10:00 EST of the *pre-dispatch day,* submit *dispatch data* for those *dispatch hours* of the *dispatch* day including, where applicable, the daily *energy* limit for the *facility* for

the *dispatch day*. The *registered market participant* may then only revise such initial *dispatch data* as permitted by this section 3.3A.

3.3A.3 If a *registered market participant* for a *dispatchable generation facility* or a dispatchable *electricity storage facility* does not provide *dispatch data* in accordance with section 3.3A.2 the *facility* shall not operate in real-time without the approval of the *IESO* under section 3.3A.12.

3.3A.4 A *registered market participant* for a *dispatchable load facility* may, in the *dispatch data* submitted under section 3.3A.2, identify all or a portion of the consumption at such *registered facility* as *non-dispatchable load* in accordance with the applicable *market manual*.

3.3A.5 A *registered market participant* for a *boundary entity* may submit, between 6:00 EST and 10:00 EST of the *pre-dispatch day,* an import *offer* or export *bid* for the next *dispatch day* with a valid NERC tag identifier. If the import *offer* is included in the s*chedule of record* determined under section 5.8, the *registered market participant* will receive the day-ahead *intertie* offer guarantee determined under section 3.8A of Chapter 9.

3.3A.6 R*egistered market participants* that submitted *offers* or *bids* in accordance with either section 3.3A.2 or section 3.3A.5 shall require *IESO* approval to modify those *offers* or *bids* between 10:00 EST and 14:00 EST except for *registered market participants* for:

a. *dispatchable* hydroelectric *generation facilities* which submitted a *daily cascading hydroelectric dependency* in accordance with section 2.2.6K and which are designated by the *IESO* as eligible *energy* limited resources, and

b. physical generation units associated with a *pseudo-unit* designated in accordance with section 2.2.6G.

3.3A.7 [Intentionally left blank – section deleted]

Market Participant Revisions to Dispatch Data

3.3A.8 Subject to sections 3.3A.9, 3.3A.10 and 3.3A.14, after 14:00 EST a *registered market participant* may submit revised *dispatch data* with respect to any *dispatch hour* without restriction until 2 hours prior to the beginning of that *dispatch hour*.

3.3A.9 Subject to sections 3.3A.10 and 3.3A.14, a *registered market participant* for a *dispatchable generation facility* or a dispatchable *electricity storage facility* who did submit *dispatch data* under section 3.3A.2 may revise its *offer* in real-time

provided the revised *dispatch data* does not increase the number of hours offered or the offered quantity in any hour relative to the *dispatch data* submitted under section 3.3A.2. Revised *offers* which represent increases to the number of hours offered or increases to the offered quantity relative to the *dispatch data* submitted under section 3.3A.2 will require *IESO* approval. Changes to daily *energy* limits will not require *IESO* approval.

3.3A.10 A *registered market participant* for a *dispatchable generation facility* who was deemed to have accepted the day-ahead production cost guarantee in accordance with section 5.8.4 shall not increase the *offer* price associated with the *minimum loading point* of the *facility*.

3.3A.11 *A registered market participant* for a *dispatchable load facility* that declared its intent for all or a portion of its consumption to be non-*dispatchable* under sections 3.3A.2 and 3.3A.4 will require *IESO* approval to increase its declared *bid* quantity and *bid* that consumption in real-time as *dispatchable load*.

3.3A.12 The *IESO* shall approve increases to declared availability of a *dispatchable facility* if that *generation facility, electricity storage facility* or *dispatchable load facility* returns from outage earlier than planned, or if the *IESO* has solicited additional *offers* and *bids*, or if such increases will avoid an *emergency operating state* or *high-risk operating state*, or as permitted under section 3.3.6.3.

3.3A.13 A *registered market participant* for a *boundary entity* who is eligible to receive a day-ahead *intertie offer* guarantee for an import transaction in accordance with section 3.3A.5 shall not revise the submitted *dispatch data* to link that import transaction to an export transaction as described in section 3.5.8.2 of Chapter 7. If the *IESO* determines that the *dispatch data* was revised by the *registered market participant* in the manner described above, the *IESO* shall recover from the *registered market participant* any day-ahead *intertie offer* guarantee payment for that import transaction and shall redistribute the payment in accordance with chapter 9, section 4.8.2.11.

3.3A.14 A *registered market participant* for a *dispatchable generation facility* who was deemed to have accepted the day-ahead production cost guarantee in accordance with section 5.8.4 shall be subject to a withdrawal charge as per section 3.8F of Chapter 9 if the *registered market participant* withdraws the *offer* for the *facility.*

3.4 The Form of Dispatch Data

3.4.1 *Dispatch data* shall relate to a specified *dispatch hour* of the *dispatch day* and to a specified *registered facility*, shall comply with the applicable provisions of this section and sections 3.5 to 3.9 and shall take one of the following forms:

3.4.1.1 for a *dispatchable generation facility*, or a dispatchable *electricity storage facility* proposing to inject *energy* an *offer* to provide a *physical service* to the appropriate *real-time market*. *Offers* accepted result in sales in the *real-time market* only to the extent that, for the *registered market participant* submitting such *offers*, the total value of the *physical services* provided to the *real-time markets* is greater than the total value of the *physical bilateral contract quantities* notified to the *IESO* in respect of that *registered market participant* pursuant to Chapter 8;

3.4.1.1.1 for a *dispatchable generation facility* that is classified as v*ariable generation,* an offer to provide a *physical service* to the appropriate *real-time market* reflecting its *generation facility's* full capacity available for production, determined in accordance with the applicable *market manual.*

3.4.1.2 for a *dispatchable load facility*, or a dispatchable *electricity storage facility* proposing to withdraw *energy* a *bid* to take *energy* from the *energy market*. *Bids* accepted result in purchases in the *real-time market* only to the extent that, for the *registered market participant* submitting such *bids*, the total value of the *physical services* taken from the *real-time markets* is greater than the total value of *physical bilateral contract quantities* notified to the *IESO* in respect of that *registered market participant* pursuant to Chapter 8;

3.4.1.2A [Intentionally left blank – section deleted]

3.4.1.3 for a self-scheduling generation facility or a *self-scheduling electricity storage facility*, a self-schedule for the provision of energy to the energy market. Energy actually provided by a *self-scheduling facility* results in sales in the real-time market only to the extent that, for the registered market participant designated for that *self-scheduling facility*, the total value of energy provided to the real-time market is greater than the total value of physical bilateral contract quantities notified to the IESO in respect of that registered market participant pursuant to Chapter 8;

3.4.1.4 for an *intermittent generator*, a forecast of *energy* expected to be provided to the *energy market*. *Energy* actually provided by an *intermittent generator* results in sales in the *real-time market* only to the extent that, for the *registered market participant* designated for such *intermittent generator*, the total value of *energy* provided

to the *real-time market* is greater than the total value of *physical bilateral contract quantities* notified to the *IESO* by that *registered market participant* pursuant to Chapter 8;

3.4.1.4A for a *transitional scheduling generator*, a forecast schedule for the provision of *energy to the energy market*; and

3.4.1.4B [Intentionally left blank – section deleted]

3.4.1.5 [Intentionally left blank – section deleted]

3.4.1.6 for a capacity market participant with an hourly demand response resource, a demand response energy bid to reduce its energy consumption during a specified availability window and obligation period in accordance with the applicable market manual.

3.4.2 Each *transmitter* shall submit to the *IESO* information on the status of its *transmission system* as described in section 3.9.

3.4.3 Each *offer* or *bid* for any *physical service* shall contain prices, each with an associated quantity. A price and the associated quantity in an *offer* or *bid* is a *price-quantity pair* and shall comply with sections 3.5 and 3.6 and the following:

3.4.3.1 the quantity in any *price-quantity pair*, other than in the first *price-quantity pair*, shall be a cumulative quantity representing the maximum quantity the *registered market participant* is offering to sell or bidding to buy, respectively, at the associated price in the *price-quantity pair*;

3.4.3.1A [Intentionally left blank – section deleted]

3.4.3.2 in any *offer*, the price in each *price-quantity pair* must not decrease as the associated quantity increases; and

3.4.3.3 in any *bid*, the price in each *price-quantity pair* must not increase as the associated quantity increases.

3.4.4 The *market price* of *energy*, in $/MWh, at and below which the *IESO* may instruct a *generation facility* to reduce its *energy* output to zero shall be:

3.4.4.1 [Intentionally left blank]

3.4.4.2 in the case of a *generation facility* other than a *self-scheduling generation facility* or an *intermittent generator*, the lowest price in any *price-quantity pair* submitted with respect to such *facility*.

Such price may be zero or negative but may not be less than negative *MMCP*.

3.4.4A Every submission of *dispatch data* with respect to a *self-scheduling generation facility* or an *intermittent generator* shall specify a price, in $/MWh, at and below which the applicable *registered market participant* reasonably expects to reduce the *energy* output of such *self-scheduling generation facility* or *intermittent generator* to zero. Such price may be zero or negative but may not be less than negative *MMCP*.

3.4.4B The *market price* of *energy*, in $/MWh, at and below which the *IESO* may instruct an *electricity storage facility* to reduce its injections of *energy* to zero shall be:

3.4.4B.1 in the case of an *electricity storage facility* other than a *self-scheduling electricity storage facility* the lowest price in any *price-quantity pair* submitted with respect to such *facility*.

Such price may be zero or negative but may not be less than negative *MMCP*.

3.4.4C Every submission of *dispatch data* with respect to a *self-scheduling electricity storage facility* shall specify a price, in $/MWh, at and below which the applicable *registered market participant* reasonably expects to reduce the injections of *energy* from *self-scheduling electricity storage facility* to zero. Such price may be zero or negative but may not be less than negative *MMCP*.

3.4.5 Every submission of *dispatch data* with respect to a *dispatchable load facility* or a dispatchable *electricity storage facility* proposing to withdraw *energy* shall specify a *market price* of *energy*, in $/MWh, at and above which the *IESO* may instruct the *facility* to reduce its *energy* withdrawals to zero. Such price shall not be greater than *MMCP*.

3.5 Energy Offers and Energy Bids

3.5.1 A registered market participant may submit no more than one energy offer or one energy bid with respect to a given registered facility for any dispatch hour.

3.5.2 All *energy offers* and *energy bids* shall be submitted using such forms as may be specified by the *IESO*, which forms shall require, at a minimum, provision of all of the information specified in Appendices 7.1 and 7.2, respectively, except where the *IESO* specifies an alternative means and/or an alternative simplified form pursuant to section 3.2.2.3.

3.5.3 Each *energy offer* or *energy bid* must contain at least 2 and, may contain up to 20 *price-quantity pairs* for each *dispatch hour*. The price in each such *price-quantity pair* shall be not more than the *Maximum Market Clearing Price* or *MMCP* and

not less than the negative *Maximum Market Clearing Price* or negative *MMCP* and shall be expressed in dollars and whole cents per MWh. The quantity in each such *price-quantity pair* shall:

3.5.3.1 in the case of a *registered facility* other than a *boundary entity*, be expressed in MW (or MWh/hour) to one decimal place and shall not be less than 0.0 MW (or 0.0 MWh/hour); or

3.5.3.2 in the case of a *registered facility* that is a *boundary entity*, be expressed in whole MW (or MWh/hour) and shall not be less than 0 MW (or 0 MWh/hour).

The quantity in the first *price-quantity pair* shall be 0.0 MW (or 0.0 MWh/hour) or 0 MW (or 0 MWh/hour) as applicable. The price in the second *price-quantity pair* shall be the same as the price in the first *price-quantity pair*.

3.5.4 Prices in *energy offers* and *energy bids* may be negative and such negative price shall imply:

3.5.4.1 when in an *energy offer*, that the *registered market participant* is willing to pay up to that price for each MWh of *energy* it injects rather than reduce its output; and

3.5.4.2 when in an *energy bid*, that the *registered market participant* is willing to take or dispose of excess *energy*, but only if paid at least that price for each excess MWh taken or disposed of.

3.5.4A The IESO Board shall establish floor prices for energy offers from variable generators that are registered market participants and for energy offers from flexible nuclear generators for flexible nuclear generation, in accordance with the applicable market manual. The prices in each energy offer submitted by the variable generator or by a flexible nuclear generator in respect of flexible nuclear generation for each dispatch hour shall not be less than the floor prices specified in the applicable market manual.

3.5.5 Each *energy offer* or *energy bid* shall contain up to 5 sets of ramp quantity and ramp up/ramp down values for each *dispatch hour*. The ramp quantity in each such set shall be the maximum MW quantity at which the corresponding ramp rate values apply, shall be expressed in MW to one decimal place and shall be greater than 0.0 MW. The ramp up and ramp down values in each such set shall be expressed in MW/minute to one decimal place and shall be greater than 0.0 MW/min. The laminations corresponding to such sets may be different from those of the *price-quantity pairs* contained in each *energy bid* or *energy offer*.

3.5.6 The largest quantity in any *energy offer* or *energy bid* for any *dispatch hour* must be at least 1.0 MWh but shall not exceed the lesser of:

3.5.6.1 the maximum output of *energy* in an hour indicated in the registration information for the relevant *registered facility*;

3.5.6.2 the maximum quantity of *energy* that can be supplied (for an *energy offer*) or taken (for an *energy bid*) in that *dispatch hour* by the *registered facility*, as estimated by the *registered market participant* for that *registered facility*; or

3.5.6.3 the maximum allowed injection (for an *energy offer*) or withdrawal (for an *energy bid*) in that *dispatch hour* through the relevant *connection point*, as limited by the lesser of:

3.5.6.3.1 the capacity of any radial line connecting the *registered facility* to the *connection point*;

3.5.6.3.2 the maximum injection or withdrawal as specified in the *connection agreement* applicable to the *registered facility*; or

3.5.6.3.3 the maximum injection or withdrawal otherwise permitted by the relevant *transmitter*.

3.5.6A Where one or more *electricity storage facilities* and one or more other *generation facilities* are all:

3.5.6A.1 connected at the same *connection point*;

3.5.6A.2 registered to the same *registered market participant,* and

3.5.6A.3 none of the *facilities* are providing *contracted ancillary services* or participating in the *operating reserve market;*

section 3.5.6 shall not apply. Instead, the largest quantity in any *energy offer* or *energy bid* for any *dispatch hour* for each *facility* must be at least 1.0 MWh but shall not exceed the lesser of:

3.5.6A.4 the maximum output of *energy* in an hour indicated in the registration information for the relevant *registered facility*;

3.5.6A.5 the maximum quantity of *energy* that can be supplied (for an *energy offer*) or taken (for an *energy bid*) in that *dispatch hour* by the *registered facility*, as estimated by the *registered market participant* for that *registered facility*; or

3.5.6A.6 the maximum allowed injection (for an *energy offer*) or withdrawal (for an *energy bid*) in that *dispatch hour* through the relevant *connection point*, as limited by the lesser of:

3.5.6A.6.1 the capacity of any radial line connecting the *registered facility* to the *connection point*; or

3.5.6A.6.2 the maximum injection or withdrawal as specified in the *connection agreements* applicable to the *registered facilities* or to the maximum injection or withdrawal otherwise permitted by the relevant *transmitter,* calculated as the total net injections and withdrawals for all *generation facilities* and *electricity storage facilities* registered to the same *registered market participant* at the same *connection point*.

3.5.6B Where one or more *electricity storage facilities* and one or more other *generation facilities* are all:

3.5.6B.1 connected at the same *connection point*;

3.5.6B.2 registered to the same *registered market participant, and*

3.5.6B.3 any of the *facilities* are providing *contracted ancillary services* or participating in the *operating reserve market;*

sections 3.5.6 and 3.5.6A shall not apply. Instead, the largest quantity in any *energy offer* or *energy bid* for any *dispatch hour* for each *facility* must be at least 1.0 MWh but shall not exceed the lesser of:

3.5.6B.4 the maximum output of *energy* in an hour indicated in the registration information for the relevant *registered facility*;

3.5.6B.5 the maximum quantity of *energy* that can be supplied (for an *energy offer*) or taken (for an *energy bid*) in that *dispatch hour* by the *registered facility*, as estimated by the *registered market participant* for that *registered facility*; or

3.5.6B.6 the maximum allowed injection (for an *energy offer*) or withdrawal (for an *energy bid*) in that *dispatch hour* through the relevant *connection point*, as limited by the lesser of:

3.5.6B.6.1 the capacity of any radial line connecting the *registered facility* to the *connection point*; or

3.5.6B.6.2 the maximum injection or withdrawal as specified in the *connection agreement* applicable to the *registered facility* or the maximum injection or withdrawal otherwise permitted by the relevant *transmitter,* and the sum of all *energy* offers or the sum of all *energy* bids from all *facilities* shall not exceed these limits.

3.5.7 A *registered market participant offering energy* from a specified *registered facility* may submit *dispatch data* specifying a maximum amount of *energy* that can be scheduled by the *IESO* for that *registered facility* over a *dispatch day*. Such a limit shall be used only in the *pre-dispatch schedule* described in section 5, and only for the purpose of providing information that the *registered market participant* may use as a basis to revise its *energy offers* in subsequent submissions.

3.5.8 All wheeling through transactions shall consist of:

3.5.8.1 an individual *energy* offer from a *boundary entity* injecting *energy* into the *IESO-controlled grid* and an *energy* bid from a *boundary entity* withdrawing *energy* from the *IESO-controlled grid*; or

3.5.8.2 an individual *energy offer* from a *boundary entity* injecting *energy* into the *IESO-controlled grid* and an *energy bid* from a *boundary entity* withdrawing *energy* from the *IESO-controlled grid,* and an identification of the desire for these to be linked, in accordance with the applicable *market manual*. The *IESO* shall assess so identified *offers* separately from their associated *bids*. The *IESO* shall schedule and *dispatch* the linked *offers* and *bids* such that both are equal to the lower of the *offer* or *bid* that would otherwise be scheduled and *dispatched*.

3.5.9 An *energy bid* submitted by a *registered market participant* for a *boundary entity* in respect of the withdrawal from the *IESO-controlled grid* of *energy* destined for an *intertie zone* in the United States of America shall constitute a declaration by a *registered market participant* for the *boundary entity* of an intention to export *energy* in the circumstances described in paragraphs 1(b) to 1(d) of Part V of Schedule VI of the *Excise Tax Act* (Canada).

3.6 Operating Reserve Offers

3.6.1 A *registered market participant* may not submit, for any *registered facility*, more than one *offer* to provide each class of operating reserve in any *dispatch hour*.

3.6.2 Each *offer* to provide *operating reserve* must contain at least 2 and may contain up to 5 *price-quantity pairs* for each class of *operating reserve* for each *dispatch hour*. The price in each such *price-quantity pair* shall be not more than the *Maximum Operating Reserve Price* or *MORP* and not less than zero and shall be expressed in dollars and whole cents per MW. The quantity in each such *price-quantity pair* shall:

3.6.2.1 in the case of a *registered facility* other than a *boundary entity*, be expressed in MW to one decimal place and shall not be less than 0.0 MW; or

3.6.2.2 in the case of a *registered facility* that is a *boundary entity*, be expressed in whole MW and shall not be less than 0 MW.

The quantity in the first *price-quantity pair* shall be 0.0 MW (or 0.0 MWh/hour) or 0 MW (or 0 MWh/hour) as applicable. The price in the second *price-quantity pair* shall be the same as the price in the first *price-quantity pair*.

3.6.3 Each *offer* to provide *operating reserve* shall be accompanied by a corresponding *energy offer* or *energy bid* that covers the same MW range.

3.6.4 *Offers* to supply *operating reserve* shall be submitted in such form as may be specified by the *IESO*, which form shall require, at a minimum, provision of all of the information specified in Appendix 7.3, except where the *IESO* specifies an alternative means and/or an alternative simplified form pursuant to section 3.2.2.3.

3.7 Self-Scheduling Generators

3.7.1 A registered market participant for a self-scheduling generation facility shall submit dispatch data indicating the amount of energy that the registered market participant reasonably expects to be provided by that self-scheduling generation facility in each dispatch hour. Such dispatch data shall:

3.7.1.1 be submitted to the *IESO* in such form as may be specified by the *IESO*, including provision of the applicable information specified in Appendix 7.1; and

3.7.1.2 comply with section 3.4.4A.

3.7A Self-Scheduling Electricity Storage

3.7A.1 A registered market participant for a self-scheduling electricity storage facility shall submit dispatch data indicating the amount of energy that the registered

market participant reasonably expects to be injected by that self-scheduling electricity storage facility in each dispatch hour. Such dispatch data shall:

3.7A.1.1 be submitted to the *IESO* in such form as may be specified by the *IESO*, including provision of the applicable information specified in Appendix 7.1; and

3.7A.1.2 comply with section 3.4.4C

3.7A.2 Subject to section 1.7 defining when the day-ahead commitment process shall function, a *registered market participant* for a *registered facility* that is a *self-scheduling electricity storage facility* shall submit *dispatch data* after 6:00 EST but before 10:00 EST of the *pre-dispatch day* in accordance with section 3.7A.1.

3.7.2 A *registered market participant* for a self-scheduling *cogeneration facility* or self-scheduling *enhanced combined cycle facility* shall ensure its *facility* operates in accordance with its *dispatch data* within the tolerances for updating *dispatch data* outlined in section 3.3.8.

3.7.3 Subject to section 1.7 defining when the day-ahead commitment process shall function, a *registered market participant* for a *registered facility* that is a *self-scheduling generation facility* shall submit *dispatch data* after 6:00 EST but before 10:00 EST of the *pre-dispatch day* in accordance with section 3.7.1.

3.8 Intermittent Generators

3.8.1 A *registered market participant* for an *intermittent generator* shall submit *dispatch data* indicating its best forecast of the amount of *energy* that the *intermittent generator* will inject in each *dispatch hour*. Such *dispatch data* shall:

3.8.1.1 be submitted to the *IESO* in such form as may be specified by the *IESO*, including provision of the applicable information specified in Appendix 7.1; and

3.8.1.2 comply with section 3.4.4A.

3.8.2 Subject to section 1.7 defining when the day-ahead commitment process shall function, a *registered market participant* for a *registered facility* that is an *intermittent generator* shall submit *dispatch data* after 6:00 EST but before 10:00 EST of the *pre-dispatch day* indicating its best forecast of the amount of energy that the *intermittent generator* will inject in each *dispatch hour* of the next *dispatch day* in accordance with section 3.8.1.

3.8A Transitional Scheduling Generators

3.8A.1 A registered market participant for a registered facility that is a transitional scheduling generator shall submit dispatch data indicating its forecast of the amount of energy that the transitional scheduling generator will inject in each dispatch hour of the dispatch day. Such dispatch data shall be submitted to the IESO for the initial pre-dispatch schedule in accordance with section 3.3.1 and in such form as may be specified by the IESO.

3.8A.2 Subject to section 1.7 defining when the day-ahead commitment process shall function, a *registered market participant* for a *registered facility* that is a *transitional scheduling generator* shall submit *dispatch data* after 6:00 EST but before 10:00 EST of the *pre-dispatch day* indicating its forecast of the amount of *energy* that the *transitional scheduling generator* will inject in each *dispatch hour* of the next *dispatch day* in accordance with section 3.8A.1.

3.9 Transmission System Information

3.9.1 Each *transmitter* whose *transmission system* is part of the *IESO-controlled grid* shall provide the *IESO* with the *transmission system* information described in Appendix 7.4 in such form as the *IESO* may specify.

3.9.2 Each *transmitter* referred to in section 3.9.1 shall update the information described in Appendix 7.4 so that it is current at:

3.9.2.1 15:00 EST on the day which is two days prior to the relevant *dispatch day*;

3.9.2.2 05:00 EST on the *pre-dispatch day*;

3.9.2.3 10:00 EST on the *pre-dispatch day*; and

3.9.2.4 any time subsequent to 10:00 EST on the *pre-dispatch day* up to the beginning of the relevant *dispatch hour* if there is a material change in the information required by this section.

4. The Dispatch Algorithm

4.1 Purpose of the Dispatch Algorithm

4.1.1 The *IESO* shall determine the various schedules and prices required by this Chapter to be developed by it using a *dispatch algorithm* based on the

mathematical techniques of constrained optimisation. The form and use of this *dispatch algorithm* are summarised in this section 4 and detailed in Appendix 7.5.

4.2 Uses of the Dispatch Algorithm

4.2.1 The *IESO* may use different numerical values in, or different computerised versions of, the *dispatch algorithm* for each of the several purposes described in this Chapter, but shall keep the objective, mathematical formulation and solution procedures the same, except as specifically noted.

4.2.2 The *IESO* shall, as far as practical, use the outputs of the *dispatch algorithm* to determine the *dispatch instructions* that guide actual physical operations of the *electricity system*. However, because any *dispatch algorithm* is only an approximation of a complex physical reality and may sometimes malfunction, the *IESO* may modify or override the results of the *dispatch algorithm* when issuing *dispatch instructions* pursuant to section 7.

4.2.3 The *IESO* shall no less than once in each calendar month, *publish* a report listing and giving reasons for all significant differences between *dispatch instructions* issued and the results of the *dispatch algorithm*.

4.2.4 Unless otherwise directed by the *IESO Board*, the *IESO* shall no less than once every two calendar years, commission and *publish* the results of an independent review of the operation and application of the *dispatch algorithm* and the related *dispatch* processes and procedures. The *IESO* shall use the results of such review to determine the need or otherwise for improvements in the related *dispatch* processes and procedures in meeting the objectives of the *market rules* and/or the mathematical representation of the *electricity system* or the solution procedures which form part of the market clearing logic. The first such review shall be completed no later than May 1, 2004.

4.3 The Optimisation Objective

4.3.1 The *dispatch algorithm* shall have as its mathematical objective function maximising the economic gain from trade among *market participants* as defined in section 4.3.2.

4.3.2 The economic gain from trade shall be defined as the difference between the value of the electricity produced (as indicated by the *energy demand* from *non-dispatchable loads* and the *energy bids* from *dispatchable loads*) and the cost of producing that electricity (as indicated by the *offers* to supply the *energy* and *operating reserves* necessary to *reliably* deliver that electricity to loads).

4.3.3 Maximising the economic gain from trade will determine quantities and prices that "clear the market," in the sense that, given the market-clearing prices and the *dispatch data*, no *market participant* would be economically better off (in terms of the *dispatch data* it submitted itself) producing or withdrawing more or less than the market-clearing quantity of any *physical service*.

4.4 Inputs to the Dispatch Algorithm

4.4.1 The *IESO* shall use as inputs to the *dispatch algorithm* the data and information outlined in section 4.4 and described in more detail in Appendix 7.5.

4.4.1A [Intentionally left blank]

4.4.2 The cost to suppliers of *energy* and *operating reserves* and the value to *dispatchable loads* of delivered electricity shall be based on the most recent valid *offers* and *bids* (including standing *dispatch data*) submitted by *registered market participants* with respect to *dispatchable generation facilities,* dispatchable *electricity storage facilities* and *dispatchable load facilities*.

4.4.3 Subject to section 4.4.3A, the price-insensitive load to be met shall be the sum of:

4.4.3.1 the net energy injections (injections minus withdrawals) by all non-dispatchable load facilities, self-scheduling generation facilities, *self-scheduling electricity storage facilities* and intermittent generators and transitional scheduling generators; and

4.4.3.2 any net amount by which the actual net injections (injections minus withdrawals) by all *dispatchable generation facilities,* dispatchable *electricity storage facilities* and *dispatchable load facilities* is less than the net amount implied by the *IESO's dispatch instructions* to such *facilities*.

4.4.3A Until such time that locational pricing is implemented in the *IESO-administered markets*, the price-insensitive load to be met shall be determined solely on the basis of the net *energy* injections referred to in section 4.4.3.1.

4.4.4 Limits on *intertie* flows between the *integrated power system* and neighbouring *transmission systems* shall be based on:

4.4.4.1 a simple model that assumes that each *intertie meter* is *connected* to an isolated *intertie zone* by a single transmission line;

4.4.4.2 the *IESO's* best estimate of the maximum flow on the single transmission line to each *intertie zone*, given the status of the

neighbouring *transmission systems* and expected or actual unscheduled flows (including as unscheduled flows any flows planned by the *IESO* to balance interchange accounts with other *control area operators*). The *IESO's* best estimate of the maximum flow on the single transmission line to an *intertie zone* may reflect the *integrated power system's* limited capability to supply and export *energy* to an *intertie zone* and applicable neighbouring *transmission system* without scheduling imported *energy* to supply the exported *energy*; and

4.4.4.3 a net *interchange schedule* limit to represent the *integrated power system's* ability to respond to hourly *interchange schedule* deviations and maintain the *reliability* of the *IESO-controlled grid*.

4.4.5 Constraints on the use of the *IESO-controlled grid* shall be determined on the basis of such system *security* requirements as the *IESO* may determine necessary to maintain *reliable* system operations, which requirements shall include, at a minimum, the following:

4.4.5.1 the largest applicable *contingency events* and any increments above these required to satisfy applicable *reliability standards*;

4.4.5.2 *security* constraints on identified *facilities*;

4.4.5.3 minimum requirements for each class of *operating reserve*;

4.4.5.4 the IESO's commitments to neighbouring transmission systems for operating reserves and regulation;

4.4.5.5 the availability and need for contracted *ancillary services* and *reliability must-run resources*; and

4.4.5.6 *reliability* constraints associated with *interchange schedules* as referred to in section 4.4.4.3.

4.4.6 The following basic parameters of the *dispatch algorithm* shall be as specified from time to time by the *IESO Board:*

4.4.6.1 the *maximum market clearing price* or *MMCP* that defines the maximum allowable price for *energy*, and the negative of which defines the minimum allowable price for *energy;*

4.4.6.1A the *maximum operating reserve price* or *MORP* that defines the maximum allowable price for any class of *operating reserve*; and

4.4.6.2 the penalty functions for the violation of *dispatch algorithm* constraints.

If the output of the *dispatch algorithm* fails to satisfy *non-dispatchable demand* or the *operating reserve requirements* for any class of *operating reserve* then, subject to section 8.2.2, the penalty functions referred to in section 4.4.6.2 may influence the calculation of *market prices* for *energy* and *operating reserve* in a similar fashion to *offers* and *bids.*

4.4.7 *Interchange schedule data* shall be input as a constant value for the given *dispatch hour* unless otherwise specified by the *IESO* and shall be derived in accordance with the outputs of the *dispatch algorithm* for each *dispatch hour* as determined under section 4.6.

4.5 The Constrained and Unconstrained IESO-Controlled Grids

4.5.1 The *dispatch algorithm* shall be used to determine both operating schedules that reflect the realities of the *integrated power system* and uniform prices within the *IESO control area* that ignore *transmission system* constraints. Thus, the *dispatch algorithm* shall be capable of using the following two different models for the *integrated power system:*

4.5.1.1 an *unconstrained IESO-controlled grid model*, which, other than as set out in Section 4.4.4 of Chapter 7 and Section 7.5.1 of Appendix 7.5, ignores transmission and other *security* constraints on the *IESO-controlled grid* including *interties* and assumes, in effect, that all *physical services* are provided and consumed at a single, undesignated location *connected* to several isolated *intertie zones* by single transmission lines; and

4.5.1.2 a *constrained IESO-controlled grid model*, which includes a full (but necessarily approximate) mathematical representation of the *integrated power system*, with *interconnections* modelled as single transmission lines to isolated *intertie zones* or as proportionately allocated to *intertie zones.*

4.6 Outputs of the Dispatch Algorithm

4.6.1 The *IESO* shall use the *dispatch algorithm* to determine the quantities and prices summarised in this section 4.6 and detailed in Appendix 7.5.

4.6.2 The *dispatch algorithm* shall be used with the *constrained IESO-controlled grid model* to determine, prior to each *dispatch hour* and to each *dispatch interval*, operating schedules and their associated costs and shadow prices. The principal outputs, for each *dispatch hour* or *dispatch interval,* as the case may be, shall be the following:

4.6.2.1 the amounts of *energy* (in MW or MWh/hour) and of each class of *operating reserve* (in MW) scheduled to be provided to the *integrated power system* by each *registered facility*;

4.6.2.2 the amounts of *energy* (in MW or MWh/hour) scheduled to be withdrawn from the *integrated power system* by each *registered facility*;

4.6.2.3 the deemed total cost, as defined by the prices in *offers*, of the total amounts of *energy* and *operating reserve* scheduled to be provided by *registered facilities*;

4.6.2.4 the deemed total cost, as defined by the prices in *energy bids*, the *MMCP* and the penalty functions in the *dispatch algorithm*, of any *dispatchable load* reductions, any failure to meet *non-dispatchable loads* and any constraint violations;

4.6.2.5 power flows and *energy* losses on transmission lines;

4.6.2.6 the prices of providing *energy* at each set of transmission nodes identified by the *IESO* for this purpose and, subject to section 4.6.2B, the prices of each class of *operating reserve* in each reserve area identified by the *IESO* for this purpose.

4.6.2A [Intentionally left blank]

4.6.2B Until the date that is the first day of the fourth calendar month following the *market commencement date,* calculated from the first day of the calendar month immediately following the month in which the *market commencement date* occurs, the prices of each class of *operating reserve* in each reserve area referred to in section 4.6.2.6 shall not be included as a principal output of the *dispatch algorithm*.

4.6.3 The *dispatch algorithm* shall be used with the *unconstrained IESO-controlled grid model* to determine, prior to each *dispatch hour* and at several times after each *dispatch interval*, *market schedules* and the corresponding uniform prices within the *IESO control area*. The principal outputs of this process are the following:

4.6.3.1 the *market schedule* indicating the amounts of *energy* (in MW or MWh/hour) and of each class of *operating reserve* (in MW) that would be provided to the *integrated power system* by each *registered facility* if transmission were totally unconstrained on the *IESO-controlled grid*;

4.6.3.2 the amounts of *energy* (in MW or MWh/hour) that would be withdrawn from the *integrated power system* by each *registered facility* if transmission were totally unconstrained on the *IESO-controlled grid;*

4.6.3.3 the deemed total cost, as defined by the prices in *offers*, of the total amounts of *energy* and *operating reserve* in the *market schedule*;

4.6.3.4 the deemed total cost, as defined by the prices in *energy bids*, the *MMCP* and the penalty functions in the *dispatch algorithm*, of any *dispatchable load* reductions, any failure to meet *non-dispatchable loads*, and any constraint violations that would occur if transmission were totally unconstrained on the *IESO-controlled grid*; and

4.6.3.5 the prices of providing *energy* and each class of *operating reserve* at any point within the *IESO control area* if transmission were totally unconstrained on the *IESO-controlled grid.* As provided in Chapter 9, the unconstrained prices for each *dispatch interval* shall be used for *settlement* purposes, except for *non-dispatchable loads*, who shall pay a uniform *hourly Ontario energy price* (HOEP) determined as described in section 8.3.1.

4.6.4 The *dispatch algorithm* shall be used with the constrained *IESO-controlled grid model* to determine, prior to each *dispatch hour*, *interchange schedules* and their associated costs. The *interchange schedule* for each *dispatch hour* shall be constant for the *dispatch hour* and used as inputs into the *dispatch algorithm* in accordance with section 4.4.

5. The Pre-dispatch Scheduling Process

5.1 Purpose and Timing of Pre-dispatch Schedules

5.1.1 The *IESO* shall determine *pre-dispatch schedules* in order to provide itself and *market participants* with advance information and projections necessary to plan the physical operation of the *electricity system*.

5.1.2 The *IESO* shall determine an initial *pre-dispatch schedule* for the 24 *dispatch hour*s of each *dispatch day* no later than 16:00 EST on the *pre-dispatch day*.

5.1.3 The *IESO* shall prepare a revised *pre-dispatch schedule* for each *dispatch day* whenever the *IESO* determines that changed circumstances have made the previous *pre-dispatch schedule* materially incorrect. A revised *pre-dispatch schedule* shall be determined only for *dispatch hours* following the changes that make it necessary.

5.1.4 Each time the *IESO* determines a *pre-dispatch schedule*, it shall also determine the associated projected *market prices* for *energy* and *operating reserve* and the associated projected *market schedule*.

5.1.5 The *IESO* shall *publish* and release to *market participants* each *pre-dispatch schedule* as provided in section 5.5. The most recently *published pre-dispatch schedule* shall supersede all previous *pre-dispatch schedules* for the same *dispatch hours*.

5.2 Information Used to Determine Pre-dispatch Schedules

5.2.1 The *IESO* shall use the following information for determining and updating the *pre-dispatch schedule* in accordance with section 5.3, using in each case the most current valid information:

5.2.1.1 dispatch data submitted by registered market participants;

5.2.1.2 the IESO's own forecasts of non-dispatchable load, and of generation by intermittent generators, transitional scheduling generators and self-scheduling generation facilities with name-plate ratings of less than 10 MW and *self-scheduling electricity storage facilities* with an *electricity storage facility size* of less than 10 MW;

5.2.1.3 the *transmission system* information provided by each *transmitter* pursuant to section 3.9;

5.2.1.4 the amount and location of *contracted ancillary services* under contract to the *IESO*;

5.2.1.5 the expected initial loading of each generator, *electricity storage facility* and *dispatchable load*, as determined based on the most current *pre-dispatch schedule* or, if applicable, *real-time schedule*; and

5.2.1.6 such other available information as the *IESO* determines appropriate including the *interchange schedule data* which are a result of the applicable *interchange schedule* protocol as defined in the applicable *market manual* and which may result in setting an upper limit for *energy* quantities scheduled in subsequent *pre-dispatch schedules*.

5.3 Determining the Pre-dispatch Schedule

5.3.1 The *IESO* shall use the information described in section 5.2 and the *dispatch algorithm* to determine a *pre-dispatch schedule* as follows:

5.3.1.1 the constrained *IESO-controlled grid* model shall be used;

5.3.1.2 the parameters defining the condition of the *integrated power system*, and any unscheduled flows between the *integrated power system* and neighbouring *control areas or* neighbouring *transmission systems*, shall be represented at their expected values in each *dispatch hour* of the *dispatch day*;

5.3.1.3 a *pre-dispatch schedule* shall be determined for each of the 24 *dispatch hours* of the *dispatch day* in sequence, with each *dispatch hour* assumed to be independent of the others except that the loading of each generator, *electricity storage facility* and *dispatchable load* for each *dispatch hour* shall be set equal to its value at the end of the preceding *dispatch hour*; and

5.3.1.4 for a *registered facility* that has specified a daily *energy* limit pursuant to section 3.5.7, hourly production amounts shall be cumulated until the first *dispatch hour* in which the *energy* limit is reached or exceeded, and the *energy* production of that *registered facility* shall be set to zero for all subsequent *dispatch hours* in that *dispatch day.*

5.3.2 If conditions or projections change materially during the *pre-dispatch day* or the *dispatch day*, the *IESO* shall use the *dispatch algorithm* with revised inputs reflecting the changes in conditions or projections to determine a revised *pre-dispatch schedule* for the remaining *dispatch hours* in the *dispatch day*.

5.4 Projected Market Schedules and Market Prices

5.4.1 Subject to section 5.4.2, the *IESO* shall, immediately after determining any *pre-dispatch schedule*, determine projected *market schedules* and projected *market*

prices for each of the *dispatch hours* in that *pre-dispatch schedule*. For this purpose, the *IESO* shall use the same information and data used for determining the *pre-dispatch schedule* for those *dispatch hours*, except that:

5.4.1.1 the unconstrained *IESO-controlled grid* model shall be used;

5.4.1.2 the initial conditions to be used for any *dispatch hour* in the *market schedule* shall be the final conditions of the *market schedule* for the preceding *dispatch hour*;

5.4.1.3 the total demand (including losses) to be satisfied within a *dispatch hour* in the *market schedule* shall be the same as the total demand identified in the *pre-dispatch schedule* for that *dispatch hour*; and

5.4.1.4 total system *energy* losses determined in the *pre-dispatch schedule* shall be represented as an increase in *non-dispatchable load* within the *IESO control area.*

5.4.2 Where the transmission transfer capability of an interconnection is zero for a given dispatch hour by reason of the outage of that interconnection, the projected market prices for energy and operating reserve for the intertie zone associated with such interconnection shall be equal to the projected uniform market prices for energy and operating reserve for the IESO control area for that dispatch hour.

5.4.3 The *IESO* may use other available information for the purposes of determining *market schedules* including *interchange schedule data* which is the outcome of those protocols identified in section 5.2.1.6 which may result in the setting of an upper limit for *energy* quantities scheduled in subsequent *market schedules*.

5.5 Release of Pre-dispatch Schedule Information

5.5.1 The *IESO* shall release the initial *pre-dispatch schedule* and associated projections of *market schedules* and shall publish *market prices* by 16:00 EST of each *pre-dispatch day*, and shall release any revised *pre-dispatch schedules* and projections of *market schedules* and shall publish *market prices* as soon as practical after they are determined. The information to be released to *market participants* is described in this section 5.5.

5.5.2 For each registered facility that is a boundary entity, a dispatchable load facility, a dispatchable generation facility, a dispatchable *electricity storage facility*, or an hourly demand response resource in respect of which a valid bid or offer for at least one dispatch hour of the applicable dispatch day has been submitted, the IESO shall release the following information only to the registered market participant for that registered facility:

5.5.2.1 the pre-dispatch schedule for that registered facility;

5.5.2.2 the projected market schedule for that *registered facility*; and

5.5.2.3 [Intentionally left blank]

5.5.2.4 any requirement of that *registered facility* to submit an *offer* or *bid* under a *reliability must-run contract* and the expected scheduled use of that *registered facility* under *contracted ancillary service* contracts.

5.5.3 The *IESO* shall release to all *market participants* the following information for each *dispatch hour*:

5.5.3.1 total system load and total system losses;

5.5.3.2 area *operating reserve* requirements;

5.5.3.3 [Intentionally left blank]

5.5.3.4 projected hourly *energy* shortfalls;

5.5.3.5 aggregate *reliability must-run resources* being directed to submit *offers* or *bids*;

5.5.3.6 any area *operating reserve* shortfalls;

5.5.3.7 a list of the network constraints and *security* constraints that affect the *pre-dispatch schedule*;

5.5.3.8 [Intentionally left blank – section deleted]

5.5.3.9 the projected uniform market prices of *energy* and *operating reserves* in the *IESO control area*; and

5.5.3.10 the projected market prices of energy and operating reserves in each intertie zone outside the *IESO control area*.

5.5.3A Until the date that is the first day of the fourth calendar month following the *market commencement date*, calculated from the first day of the calendar month immediately following the month in which the *market commencement date* occurs, the *IESO* shall not be required to release the prices of each class of *operating reserve* referred to in section 5.5.3B.2.

5.5.3B Where the *IESO* determines and releases a *pre-dispatch schedule*, the *IESO* shall include in such *pre-dispatch schedule*, for information purposes only:

5.5.3B.1 the projected *energy prices* at each set of transmission nodes identified by the *IESO* for this purpose; and

5.5.3B.2 subject to section 5.5.3A, the projected prices of each class of *operating reserve* in each reserve area identified by the *IESO* for this purpose,

for the *dispatch hour* immediately following the hour in which such *pre-dispatch schedule* is determined and released.

5.5.4 If the *IESO* determines that release of specific types of information in the *pre-dispatch schedule* may facilitate anti-competitive behaviour, the *IESO* may limit the release of such information through an *urgent amendment* to these *market rules*. The *IESO* shall advise the *market surveillance panel* of the matter. The *IESO Board* may request the advice of the *market surveillance panel* of the need or otherwise for the *urgent amendment* to remain in effect.

5.6 [Intentionally left blank – section deleted]

5.6.1 [Intentionally left blank – section deleted]

5.6.2 [Intentionally left blank – section deleted]

5.7 Pre-Dispatch Scheduling of Generation Facilities Eligible for the Generation Cost Guarantee

5.7.1 A *generation facility* shall be eligible on a voluntary basis for the generation cost guarantee on a *per-start* basis for a given *dispatch hour*, provided that:

5.7.1.1 the criteria specified in section 2.2B have been met:

5.7.1.2 subject to section 5.7.2, the *offer* price in the submitted *price-quantity pair* corresponding to the *minimum loading point* for that *generation facility* for all hours of the *minimum generation block run-time* must be the same until after the *IESO* has constrained on the *generation facility* as specified in section 6.3A.2;

5.7.1.3 the *generation facility* is scheduled in any *pre-dispatch schedule* determined within 3 hours ahead of the *dispatch hour:*

a. for the *dispatch hour*; and

b. for at least half of *minimum generation block run-time*, rounded up, at *minimum loading point* or higher, during the period from *dispatch hour* until the earlier of:

- the end of the period representing *minimum generation block run-time*; or
- the end of the period representing *minimum run-time*;

Any schedule resulting from either a constraint associated with a day-ahead commitment or a manual constraint applied by the *IESO* at the *generator's* request shall be excluded from the eligibility test in this section 5.7.1.3;

5.7.1.4 the registered market participant for the generation facility does not increase the offer prices in its submitted price-quantity pairs corresponding to the generation facility's minimum loading point for the minimum generation block run-time after notifying the IESO of its intention to synchronize under section 5.7.1.6 or after the IESO has applied a manual constraint under section 6.3A.4;

5.7.1.5 the *generation facility* is not already synchronized at the time of the publication of the applicable *pre-dispatch schedule* referred to in section 5.7.1.3;

5.7.1.6 the *registered market participant* for the *generation facility* notifies the *IESO* of its intention to synchronize and then run for at least the *minimum generation block run-time* in accordance with applicable *market manual*; and

5.7.1.7 at the time of notification of intention to synchronize made in accordance with section 5.7.1.4, the *registered market participant* for the *generation facility* also notifies the *IESO* of its intention to qualify for the generation cost guarantee.

5.7.2 The *offer* price corresponding to *minimum loading point* in the *minimum generation block run-time* hours which contain a constraint associated with a day-ahead commitment will be excluded from the eligibility test in section 5.7.1.2.

5.8 The Day-Ahead Commitment Scheduling Process

5.8.1 Starting from 10:00 EST the *IESO* may in accordance with Appendix 7.5A determine the *schedule of record*.

5.8.2 Where the *IESO* determines the *schedule of record* in accordance with Section 5.8.1, it will be released by the *IESO* no later than 15:00 EST in accordance with the applicable *market manual*.

5.8.3 [Intentionally left blank – section deleted]

5.8.4 A *registered market participant* whose *facility* is eligible under section 2.2C for the day-ahead production cost guarantee and whose *facility* is included in the *schedule of record* is deemed to have accepted the guarantee for its *facility.*

5.8.5 Subject to sections 5.8.4 and 5.8.6, the *IESO* shall ensure that the scheduled output for a *facility* will meet or exceed its *minimum loading point* for all hours that it was included in the *schedule of record* in future iterations of the *pre-dispatch schedule* and in the *real-time schedule.*

5.8.6 The *IESO* may, to maintain the reliable operation of the *IESO-controlled grid*, require a *generation facility* that was included in the *schedule of record* to either de-synchronize from the *IESO-controlled grid* or to not synchronize to the *IESO-controlled grid*.

5.8.7 When determining the *schedule of record* applicable to the first hour of the next *dispatch day*, the *IESO* may disregard the net *intertie* scheduling limit.

5.8.8 [Intentionally left blank – section deleted]

6. The Real-Time Scheduling Process

6.1 Purpose and Timing of Real-Time Schedules

6.1.1 The *IESO* shall determine *real-time schedules* and use these as the primary determinant of the *dispatch instructions* the *IESO* issues to *market participants* regarding physical operation of *registered facilities* other than *boundary entities*.

6.1.2 The *IESO* shall determine, for *registered facilities* other than *boundary entities*, a *real-time schedule* for every *dispatch interval* two minutes before the *dispatch interval* to which it applies.

6.1.3 The *IESO* shall determine, for *registered facilities* that are *boundary entities*, a *real-time schedule* consisting of an *interchange schedule* for each *dispatch hour* using the outcome of the *pre-dispatch schedule* determined as at the preceding *dispatch hour* and modified as required by the *IESO*.

6.2 Information Used to Determine Real-Time Schedules

6.2.1 The *IESO* shall determine each *real-time schedule* in accordance with section 6.3 using the same type of information used for determining *pre-dispatch schedules* as described in section 5.2, updated to reflect the most recent valid *dispatch data* submitted by *registered market participants*, real-time system measurements, and the most recent projections of forecast data and other information pertaining to the *electricity system* which relates to future periods of time, as are available to the *IESO*.

6.3 Determining the Real-Time Schedule

6.3.1 The *IESO* shall use the information described in section 6.2 and the *dispatch algorithm* to determine a *real-time schedule* for each *dispatch interval* as follows:

6.3.1.1 the constrained *IESO-controlled grid* model shall be used;

6.3.1.2 *intertie* flows at the beginning of each *dispatch interval* shall be set at the *IESO's* best estimate of their actual values, as determined from real-time system data or applicable *interchange schedules* to reflect actual unscheduled flows;

6.3.1.3 *intertie* flows at the end of each *dispatch interval* shall be set at the value ascribed to such flows in the relevant *interchange schedule*;

6.3.1.4 the output level of each generator, and each *electricity storage facility*, and the withdrawal levels of each *dispatchable load, non-dispatchable load,* and *electricity storage facility* at the beginning of the *dispatch interval* shall be set at the *IESO's* best estimate of their actual values, as determined from real-time system data or the *real-time schedule* for the preceding *dispatch interval*; and

6.3.1.5 no daily *energy* limit specified for a *registered facility* pursuant to section 3.5.7 shall be taken into account in determining *real-time schedules*.

6.3A Real-Time Scheduling of Generation Facilities Eligible for the Generation Cost Guarantee

6.3A.1 After the *registered market participant* for a *generation facility* eligible for the generation cost guarantee notifies the *IESO* of its intent to synchronize pursuant to section 5.7 of Chapter 7, that *generation facility* shall synchronize, unless otherwise agreed to by the *IESO*, before the end of the specified *dispatch hour*

and, subject to section 6.3A.3, run until the end of the *minimum generation block run-time*.

6.3A.2 The *IESO* shall, unless there is an adverse impact on the *reliable* operation of the *IESO-controlled grid*, if necessary to respect the *minimum generation block run-time* submitted by the *market participant* for the *generation facility*, constrain on the *facility* at its *minimum loading point* for the specified *minimum generation block run-time*.

6.3A.3 If the *IESO*, for reasons of *reliability*, constrains off the *generation facility* such that the *generation facility* has to de-synchronize before the end of its *minimum generation block run-time*, the *generation facility* shall remain eligible for the generation cost guarantee.

6.3A.4 In consultation with the *registered market participant*, the *IESO* may, for *reliability* reasons, during the time period from the release of the *pre-dispatch schedule* until the *dispatch hour*, manually apply a constraint to a *generation facility* that submitted *offers* into the *pre-dispatch schedule* to ensure that the output from that *generation facility* is scheduled for at least its *minimum generation block run time*. If the *IESO* applies that manual constraint, the *generator* will be deemed to have accepted the generation cost guarantee provided that:

- the criteria specified in sections 5.7.1.1 and 5.7.1.4 are satisfied; and
- the *generation facility* is not synchronized at the time the manual constraint is applied.

6.3B Real-Time Scheduling of Generation Facilities Eligible for the Day-Ahead Production Cost Guarantee

6.3B.1 If the *IESO*, for reasons of reliability, requires a *generation facility* that was eligible for the day-ahead production cost guarantee under section 2.2C to either de-synchronize from the *IESO-controlled grid* or to not synchronize to the *IESO-controlled grid* such that the *generation facility* does not comply with its *schedule of record*, the *generation facility* shall remain eligible for the day-ahead production cost guarantee. The *registered market participant* for the *generation facility* may also apply to the *IESO* for additional compensation under section 4.7E.1 of Chapter 9.

6.3B.2 If a *generation facility* that was eligible for the day-ahead production cost guarantee under section 2.2C does not close its breaker by the start of the first interval of the first hour of its *schedule of record* due to reasons not specified in

sections 6.3B.1or 6.3B.3 then the *generation facility* shall not remain eligible for the day-ahead production cost guarantee associated with that start determined in accordance with section 5.8 nor shall the *registered market participant* for the *generation facility* be eligible to apply to the *IESO* for additional compensation under section 4.7E.1 of Chapter 9.

6.3B.3 If a *generation facility* that was eligible for the day-ahead production cost guarantee under section 2.2C does not comply with its *schedule of record* due to reasons specified in section 1.2.3 of Chapter 5 then the *facility* shall remain eligible for a pro-rated day-ahead production cost guarantee determined in accordance with section 4.7D of Chapter 9.

6.3B.4 If the *registered market participant* for a *generation facility* that was eligible for the day-ahead production cost guarantee under section 2.2C does not comply with its *schedule of record* by withdrawing the *dispatch data* for the *generation facility* the *facility* may not remain eligible for a day-ahead production cost guarantee and may be subject to a withdrawal charge as determined in accordance with section 3.8F of Chapter 9.

6.4 Market Schedules and Market Prices

6.4.1 Subject to section 8.4A the *IESO* shall, within five minutes after the end of each *dispatch interval*, use the *dispatch algorithm* to determine a *market schedule* and *market prices* for that *dispatch interval* based on the most recent *real-time schedule* for such *dispatch interval.*

6.4.2 Subject to section 8.4A for the purpose of determining the *market schedule* and *market prices* for any *dispatch interval*, the *IESO* shall use the same information and data used for determining the *real-time schedule* for that *dispatch interval,* except that:

6.4.2.1 the unconstrained *IESO-controlled grid* model shall be used;

6.4.2.2 subject to section 3.1.2 of Appendix 7.5, the initial conditions to be used for any *dispatch interval* in the *market schedule* shall be the final conditions of the *market schedule* for the preceding *dispatch interval*;

6.4.2.3 the total demand (including losses) to be satisfied within a *dispatch interval* in the *market schedule* shall be set at the *IESO's* best estimate of its actual value, as determined from real-time system data;

6.4.2.4 total system *energy* losses determined in the *real-time schedule* shall be represented as an increase in *non-dispatchable load* within the *IESO control area*;

6.4.2.5 any *registered facility* in respect of which a *forced outage* has been detected during a *dispatch interval* shall be recognized by an adjustment to the input data;

6.4.2.6 subject to section 6.4.2A, the estimated deviations between scheduled quantities and actual quantities shall be represented as a change in *non-dispatchable load* in the *IESO control area*;

6.4.2.7 subject to section 6.4.2A, the *market schedule* shall reflect dispatch adjustments computed using scheduled injections from the *constrained schedule*, outlined in Appendix 7.5;

6.4.2.8 in accordance with section 4.13.1 of Appendix 7.5, the *market schedule* may use different trading period length to that of the *real-time schedule*;

6.4.2.9 in accordance with section 2.11.2 of Appendix 7.5, the *market schedule* may use a different ramp rate for *operating reserve* to that of the *real-time schedule;*

6.4.2.9A for a *variable generator* that is a *registered market participant,* if the *registered facility* is issued a *dispatch instruction* by the *IESO* in accordance with section 7.1*,* the quantity of *energy* scheduled for injection in the *market schedule* for the applicable *dispatch intervals* shall be limited to reflect the least of the maximum MW *energy* level associated with *energy offers* submitted for the *registered facility,* the *registered facility's* full capacity less submitted *outages, and the* forecast of *energy* produced by the *forecasting entity* for the *registered facility*; and

6.4.2.9B for a *variable generator* that is a *registered market participant,* if the *registered facility* is issued a *release notification* by the *IESO* in accordance with section 7.1, which remains in effect for any *dispatch interval*, the quantity of *energy* scheduled for injection in the *market schedule* for the applicable *dispatch intervals* shall be limited to reflect the least of the maximum MW *energy* level associated with *energy offers* submitted for the *registered facility*, the *registered facility's* full capacity less submitted *outages*, and the instantaneous *energy* output of the *registered facility,* as represented by its *operating result* for that *facility,* recorded at the

end of each applicable *dispatch interval* as referred to in this section.

6.4.2A Until such time that locational pricing is implemented in the *IESO-administered markets*, in determining the *market schedule* and *market prices* for any *dispatch interval,* the *IESO* shall not have regard to the estimated deviations referred to in section 6.4.2.6 or to the dispatch adjustments referred to in section 6.4.2.7.

6.4.3 The *IESO* shall determine for *registered facilities* that are *boundary entities* a *market schedule* for each *dispatch hour* using the outcome of the projected *market schedule* determined as at the preceding *dispatch ho*ur and modified as required by the *IESO.*

6.5 Publication of Real-Time Schedule Information

6.5.1 For each *registered facility* that is a *dispatchable load facility* or a *dispatchable generation facility* in respect of which a valid *bid* or *offer* has been submitted for the applicable *dispatch hour*, the *IESO* shall, as soon as practical but no later than the start of the *dispatch interval* to which it relates, release the following information for each such *registered facility* only to the *registered market participant* for that *registered facility*:

6.5.1.1 the real-time schedule for that *registered facility*; and

6.5.1.2 [Intentionally left blank]

6.5.1.3 the scheduled use of that *registered facility* under *contracted ancillary service* contracts.

6.5.1.4 [Intentionally left blank]

6.5.1A Subject to section 8.4A, for each *registered facility* that is a *dispatchable load facility* or a *dispatchable generation facility* in respect of which a valid *bid* or *offer* has been submitted for the applicable *dispatch hour*, the *IESO* shall, within one hour after each *dispatch hour*, release to each *registered market participant* the *market schedule* for their *registered facilities* for each *dispatch interval* of that *dispatch hour.*

6.5.2 Subject to section 8.4A the *IESO* shall, in the five minute period after the end of each *dispatch interval*, release to all *market participants* the uniform *market prices* of *energy* and *operating reserves* related to that *dispatch interval*.

6.5.3 The *IESO* shall, within one hour after each *dispatch hour,* release to all *market participants* the following information for each *dispatch interval* of that *dispatch hour*:

6.5.3.1 total system load and total system losses;

6.5.3.2 area *operating reserve* requirements;

6.5.3.3 for information purposes only, *energy* prices at each set of transmission nodes identified by the *IESO* for this purpose, decomposed as far as practical into an *energy* component, a loss component and a component for all other transmission and system constraints and, subject to section 6.5.3A, the prices of each class of *operating reserve* in each reserve area identified by the *IESO* for this purpose;

6.5.3.4 [Intentionally left blank]

6.5.3.5 [Intentionally left blank]

6.5.3.6 any area *operating reserve* shortfalls; and

6.5.3.7 a list of network and *security* constraints that affected the *real-time schedule*.

6.5.3A Until the date that is the first day of the fourth calendar month following the *market commencement date*, calculated from the first day of the calendar month immediately following the month in which the *market commencement date* occurs, the *IESO* shall not be required to release the prices of each class of *operating reserve* referred to in section 6.5.3.3.

6.5.4 Subject to section 8.4A, for each *registered facility* that is a *boundary entity* in respect of which the *dispatch instructions* for a given *dispatch hour* provides for the *dispatch* of more than 0 MW or for a reduction to 0 MW relative to the previous *dispatch hour*, the *IESO* shall*,* as soon as practical and consistent with relevant *reliability standards,* but no later than the start of the *dispatch hour* to which it relates, release the following information for each such *registered facility* only to the *registered market participant* for that *registered facility:*

6.5.4.1 the interchange schedule for that *registered facility*;

6.5.4.2 [Intentionally left blank]

6.5.4.3 any request of that *registered facility* to submit an offer or bid under a *reliability must-run contract* and the scheduled use of that *registered facility* under contracted *ancillary service* contracts; and

6.5.4.4 the projected market schedule for that *registered facility*.

7. IESO Dispatch Instructions

7.1 Purpose and Timing of Dispatch Instructions

7.1.1 The *IESO* shall determine *dispatch instructions* for each *registered facility* as described in this section 7, as the primary means of co-ordinating the real-time operation of the *electricity system*.

7.1.1A The *IESO* shall only issue *dispatch instructions* for a *physical service* to a *registered facility* other than a *boundary entity* for a given *dispatch interval* when there is a change in the quantity of a *physical service* to be scheduled from that *registered facility* during that *dispatch interval* relative to the last *dispatch instruction* issued to the *registered facility* and with which the *registered market participant* has confirmed compliance in accordance with section 7.1.2 and 7.1.2A.

7.1.1B Where the *IESO*:

7.1.1B.1 is not required to issue a *dispatch instruction* at a *registered facility* other than a *boundary entity* for a given *dispatch interval* by virtue of section 7.1.1A; or

7.1.1B.2 for any reason fails to issue a dispatch instruction to a *registered facility* other than a *boundary entity* for a given *dispatch interval*,

subject to section 7.1.1B1, the last *dispatch instruction* issued to the *registered facility* and with which the *registered market participant* has confirmed compliance in accordance with sections 7.1.2 and 7.1.2A shall, for all purposes under these *market rules* but subject to section 7.1.4 and 7.4.3, be deemed to be the *dispatch instruction* issued for that *dispatch interval* for that *registered facility*.

7.1.1B1 For a *variable generator* that is a *registered market participant*, section 7.1.1B shall apply until the *registered facility* is issued a *release notification*.

7.1.1C Notwithstanding the identification of a portion of the consumption at a *registered facility* under section 3.3.18 as *non-dispatchable load,* the *IESO* shall issue *dispatch instructions* in accordance with the applicable *market manual* to that *registered facility* including that portion that has been identified pursuant to section 3.3.18 as *non-dispatchable load*.

7.1.2 Subject to section 7.1.1A, the *IESO* shall issue *dispatch instructions* for each *registered facility*, other than a *boundary entity*, for which a *dispatch instruction* is required no later than the start of each *dispatch interval* or, where section 7.1.4 or 7.4.3 applies, within a *dispatch interval*. The *IESO* shall:

7.1.2.1 [Intentionally left blank]

7.1.2.2 issue such *dispatch instructions* using the systems and protocols defined in the applicable *market manual*; and

7.1.2.3 record and time-stamp all such *dispatch instructions*, store such records for at least seven years and make such records available for purposes of audit and dispute resolution in accordance with these *market rules*.

7.1.2A Each registered market participant shall:

7.1.2A.1 acknowledge receipt of; and

7.1.2A.2 confirm its intention to comply or not to comply with,

each *dispatch instruction* issued to it in accordance with section 7.1.2 in respect of each of its *registered facilities*, other than a *boundary entity*, using the systems and protocols defined in the applicable *market manual* and within the time required by such *market manual*.

7.1.2A1 The *IESO* shall issue a *release notification* to a *variable generator* that is a *registered market participant* if the *registered facility* is not required to be at or below forecasted output. Each *variable generator* shall acknowledge receipt of each *release notification* using the systems and protocols defined in the applicable *market manual* and within the time required by such *market manual*.

7.1.2B Confirmation by a *registered market participant* of its intention not to comply with a *dispatch instruction* pursuant to section 7.1.2A shall constitute non-compliance with the *dispatch instruction* by the *registered market participant* for all purposes under these *market rules*, including but not limited to section 7.5.

7.1.2C Where a *registered market participant* has for a *registered facility* that is a *dispatchable load* identified pursuant to section 3.3.18 all or a portion of that *registered facility's* consumption as *non-dispatchable load* and the *IESO* has issued a *dispatch instruction* requiring a reduction of such non-dispatchable consumption pursuant to section 7.1.1C, the *registered market participant* shall confirm its intention not to comply with each such *dispatch instruction* in accordance with section 7.1.2A and the applicable *market manual*.

7.1.2D Confirmation by a *registered market participant* of its intention not to comply with a *dispatch instruction* pursuant to section 7.1.2C shall not constitute non-compliance with the *dispatch instruction* by the *registered market participant* for all purposes under these *market rules*, including but not limited to section 7.5.

7.1.3 The *IESO* shall issue *dispatch instructions*, in the form of *interchange schedules*, for each *registered facility* that is a *boundary entity*, for which a *dispatch instruction* is required prior to each *dispatch hour*. The *IESO* shall:

7.1.3.1 [Intentionally left blank]

7.1.3.2 issue such *dispatch instructions* using the systems and protocols defined in the applicable *market manual*; and

7.1.3.3 record and time-stamp all such *dispatch instructions,* store such records for at least seven years and make such records available for purposes of audit and dispute resolution in accordance with these *market rules*.

7.1.3A Each *registered market participant* shall acknowledge receipt of each *dispatch instruction* issued to it in accordance with section 7.1.3 in respect of each of its *registered facilities* that is a *boundary entity* using the systems and protocols defined in the applicable *market manual* and within the time required by such *market manual*.

7.1.3B [Intentionally left blank – section deleted]

7.1.3B.1 [Intentionally left blank – section deleted]

7.1.3B.2 [Intentionally left blank – section deleted]

7.1.3C [Intentionally left blank – section deleted]

7.1.4 The *IESO* may issue *dispatch instructions* within the *dispatch interval*, instructing any *registered facility* with a valid *energy offer* or *bid*, to increase or decrease *energy* production or consumption as specified in its *offers* or *bids* for *energy*.

When a *dispatch instruction* is issued within a *dispatch interval* pursuant to this section 7.1.4, the last *dispatch instruction* for *energy* or each class of *operating reserve,* as the case may be, shall be the sole *dispatch instruction* used for *settlement* purposes for that *dispatch interval.*

7.1.5 Where a *contingency event* is occurring or has occurred, the *IESO* may temporarily cease issuing *dispatch instructions* in the manner otherwise required by section 7.1.2. In such cases, *registered market participants* shall comply with section 7.3.3 or 7.4.3, as the case may be.

7.1.6 The *IESO* shall, on a best efforts basis, determine and issue *dispatch* advisories for each *registered dispatchable facility*, for information purposes only. *Dispatch* advisories are determined and issued every 5 minutes to each *registered dispatchable facility* to provide an indication of potential future *dispatch instructions* and *operating reserve* schedules.

7.2 Information Used to Determine Dispatch Instructions

7.2.1 The *IESO* shall use its best endeavours to ensure that the *dispatch instructions* issued with respect to each *registered facility*, that is not a *boundary entity*, for each *dispatch interval* closely approximate the most recent *real-time schedule* for that *registered facility* and *dispatch interval*. The *IESO* may, however, issue *dispatch instructions* that depart from the *real-time schedule* if:

7.2.1.1 the *security* and *adequacy* of the system would be endangered by implementing the most recent *real-time schedule*;

7.2.1.2 the *dispatch algorithm* has failed, or has produced a *real-time schedule* that is clearly and materially in error;

7.2.1.3 material changes subsequent to determination of the most recent *real-time schedule*, such as failure of an element of a *transmission system* or failure of a *registered facility* to follow *dispatch instructions*, have occurred; or

7.2.1.4 the operation of all or part of the *IESO-administered markets* has been suspended pursuant to section 13.

7.2.2 If the *IESO* anticipates that an over-generation or an under-generation condition may occur, it shall issue advisory notices in accordance with section 12.1 but shall continue using the procedures described in sections 5 and 6 to determine *pre-dispatch schedules*, *real-time schedules* and the associated projected and *market prices* and *market schedules.*

7.2.3 If the *IESO* determines prior to issuing *dispatch instructions* that the market responses to the projected or *market prices* will be sufficient to eliminate the over-generation or under-generation condition, the *IESO* shall take no *emergency* action and shall issue advisory notices so indicating.

7.2.4 If the *IESO* determines prior to issuing *dispatch instructions* that market responses will not eliminate the over-generation or under-generation condition, it shall declare an *emergency operating state* to resolve the conditions in accordance with section 7.7.

7.2.5 The *IESO* shall use its best endeavours to ensure that the *dispatch instructions* issued with respect to each *registered facility*, that is a *boundary entity*, for each *dispatch hour* reflect the *pre-dispatch schedule* for that *dispatch hour* as determined in accordance with section 6.1.3 of Chapter 7. The *IESO* may, however, issue *dispatch instructions* that depart from the *pre-dispatch schedule* if:

7.2.5.1 the *security* and *adequacy* of the system would be endangered by implementing the *pre-dispatch schedule*;

7.2.5.2 the *dispatch algorithm* has failed, or has produced a *pre-dispatch schedule* that is clearly and materially in error;

7.2.5.3 material changes subsequent to determination of the *pre-dispatch schedule*, such as failure of an element of a *transmission system* or failure of a *registered facility* to follow *dispatch instructions*, have occurred; or

7.2.5.4 the operation of all or part of the *IESO-administered markets* has been suspended pursuant to section 13; or

7.2.5.5 an external *control area operator* calls a *called capacity export* in accordance with section 20.

7.3 The Content of Dispatch Instructions

7.3.1 The *IESO* shall, subject to section 7.1.1A, issue *dispatch instructions* for each *dispatch interval* to each *registered facility* that is a not a *boundary entity* indicating for that *dispatch interval*:

7.3.1.1 the rate at which *energy* is to be injected into or withdrawn from the *IESO-controlled grid* (in MW) at the end of the *dispatch interval*;

7.3.1.2 the amount of each class of *operating reserve* that is to be in a condition to respond to a *dispatch instruction* issued pursuant to section 7.4.3 calling for additional *energy* production; and

7.3.1.3 the amount of *reactive support* and *regulation* that is to be provided under *contracted ancillary service* contracts or *reliability must-run contracts* or as a consequence of any requirement to provide same which derives from the application of these *market rules*.

7.3.2 The dispatch instructions for any registered facility that is not a boundary entity shall:

7.3.2.1 be consistent with the current operating status of that *registered facility* and with any operational constraints described in the most recent *dispatch data* submitted by the *registered market participant* for that *registered facility*;

7.3.2.2 be used by the *IESO* for the purpose of declaring the *registered facility* as non-conforming in accordance with section 7.5.4; and

7.3.2.3 subject to Appendix 7.6, be used in the *IESO settlement process* for determining any *settlement amounts* for congestion management pursuant to section 3.5 of Chapter 9.

7.3.3 [Intentionally left blank – section deleted]

7.3.4 The IESO shall issue dispatch instructions for each dispatch hour to each registered facility that is a boundary entity, indicating for that dispatch hour:

7.3.4.1 the rate at which *energy* is to be injected into or withdrawn from the *IESO-controlled grid* (in minutes) from the specified *intertie zone*, which rate shall be consistent with all relevant *reliability standards*;

7.3.4.2 the amount of each class of *operating reserve* that is scheduled and the ramp rates associated with the *energy* if called on; and

7.3.4.3 the amount of *reactive support* and *regulation* that is to be provided under *reliability must-run contracts* or as a consequence of any requirement to provide same which derives from the application of these *market rules.*

7.3.5 The dispatch instructions for any registered facility that is a boundary entity shall:

7.3.5.1 be consistent with the current *dispatch data* for that *registered facility* and with any *interconnection* limitations associated with the *registered facility*; and

7.3.5.2 be used in the *IESO settlement process* for determining any *settlement amounts* for congestion management pursuant to section 3.5 of Chapter 9.

7.3.6 [Intentionally left blank – section deleted]

7.4 IESO Dispatch of Operating Reserve

7.4.1 The *IESO* shall:

7.4.1.1 subject to section 7.1.1A, issue to each *registered facility*, other than a *boundary entity*, which has made an *offer* for the delivery of *operating reserve* for a particular *dispatch hour*, *dispatch instructions* for each *dispatch interval* consistent with the results of the *dispatch algorithm* and the procedures detailed in sections 6.2 to 6.4, instructing the *registered market participant* responsible for that *registered facility* as to the quantity of *operating reserve* that is to be provided by that *registered facility* in that *dispatch interval*; and

7.4.1.2 issue to each *registered facility,* that is a *boundary entity,* which has made an *offer* for the delivery of *operating reserve* for a particular *dispatch hour*, *dispatch instructions* for that *dispatch hour* consistent with the results of the *dispatch algorithm* and the procedures detailed in sections 6.1 to 6.4, instructing the *registered market participant* responsible for that *registered facility* as to the quantity of *operating reserve* to be provided by that *registered facility* in that *dispatch hour.*

7.4.2 Each *registered facility* to which section 7.4.1 applies shall maintain unused *generation capacity, electricity storage capacity,* or load reduction capacity during that *dispatch interval*, consistent with the *dispatch instructions* issued to it under these *market rules*, so as to be able to increase *energy* production or reduce *energy* withdrawal as soon as possible upon being instructed to do so by the *IESO* pursuant to section 7.4.3.

7.4.2.1 A *market participant* shall be subject to non-accessibility charges if it fails to maintain unused *generation capacity, electricity storage capacity,* or load reduction capacity equal to or greater than its total amount of scheduled *operating reserve* during any

interval in which it is scheduled to provide *operating reserve* but is not *dispatched* to increase *energy generation* or reduce energy withdrawal pursuant to section 7.4.3. The *market participant* may also be subject to compliance actions in accordance with section 6 of Chapter 3.

7.4.3 Where a *contingency event* has occurred or is occurring, the *IESO* may issue *dispatch instructions* within the *dispatch interval*, instructing a *registered facility*, other than a *boundary entity*, providing *operating reserve* to begin increasing *energy* production or reducing *energy* withdrawal as specified in its *offers* of *operating reserve*. *Dispatch instructions* issued in respect of a *registered facility* that is a *boundary entity* providing *operating reserve* shall be such as to ensure that the *energy* associated with each *offer* of *operating reserve* is scheduled by the *IESO* in a manner consistent with all relevant *reliability standards* for activation of *operating reserve* and as agreed upon by the entity scheduling the resulting *energy* transfer.

7.4.4 The *IESO* shall, when *dispatching registered facilities* providing *operating reserve* to produce *energy* pursuant to section 7.4.3, call first on the *registered facility* in each area that has offered the lowest price (in $/MWh) for *energy* produced from scheduled *operating reserve* in that area. If such *registered facility* is instructed to produce *energy* but does not do so as rapidly as instructed, or if the *IESO* needs additional *energy* from *operating reserve* in that area, the *IESO* shall call upon the *registered facility* offering the next-lowest price for *energy* from *operating reserve*. If the *IESO* determines that calling upon *registered facilities* in strict order of increasing price of *energy* would mean that it would be unable to respond in a timely fashion to a contingency for which the *IESO* would issue a *dispatch instruction* pursuant to section 7.4.3, the *IESO* may call upon *registered facilities* out of such strict order but shall as far as is practical call *registered facilities* to reflect the intent of this section 7.4.4.

7.4.5 When *operating reserves* are activated as a result of a *contingency event*, the otherwise applicable *ten-minute operating reserve* requirements shall be reduced by a corresponding amount and shall subsequently be recovered to pre-contingency levels in a manner consistent with sections 4.5.10 and 4.5.21 of Chapter 5.

7.4.6 A *registered facility* that failed to maintain unused *generation* (or load reduction) *capacity* equal to or greater than their total amount of scheduled *operating reserve* is not entitled to any inappropriate congestion management *settlement* credits determined in accordance with section 3.5.2 of Chapter 9. The *IESO* may withhold or recover such congestion management *settlement* credits and shall

redistribute any recovered payments in accordance with section 4.8.2 of Chapter 9.

7.5 Compliance with Dispatch Instructions

7.5.1 Each *registered market participant* shall ensure that each of its *registered facilities* complies with *dispatch instructions* issued to it under these *market rules*. Without limiting the generality of section 6.2 of Chapter 3, non-compliance with *dispatch instructions* other than for the reasons referred to in section 7.5.3 shall be a breach of the *market rules* and may be sanctioned in accordance with section 6.2 of Chapter 3 and with this section 7.5.

7.5.2 A *registered market participant* that expects its *registered facility*, other than a *boundary entity*, to operate in a manner that, for any reason, differs materially from the *dispatch instructions* issued to it in accordance with these *market rules* shall so notify the *IESO* as soon as possible. The *IESO* shall issue guidelines defining when a difference is material and how notice shall be provided for the purposes of this section 7.5.2 and of section 7.5.3.

7.5.3 Compliance with a *dispatch instruction* for a *registered facility* other than a *boundary entity* is not required if such compliance would endanger the safety of any person, damage equipment, or violate any *applicable law*. A *market participant* that departs from *dispatch instructions* for any such reason shall so notify the *IESO* in accordance with section 7.5.2.

7.5.4 If failure by a *registered facility,* other than a *boundary entity*, to comply with a *dispatch instruction* endangers *electricity system reliability*, the *IESO* shall declare the *registered facility* to be non-conforming and shall take any actions allowed by sections 7.5.5 to 7.5.7 or any other provisions of these *market rules* which the *IESO* determines appropriate.

7.5.4A [Intentionally left blank – section deleted]

7.5.5 Subject to section 7.5.5A, if a *registered facility* other than a *boundary entity* produces or withdraws more or less *energy* in a *dispatch interval* than implied by a valid *dispatch instruction* issued by the *IESO*, the *IESO* shall, for pricing and *settlement* purposes:

7.5.5.1 treat the difference in *energy* production or withdrawal as a change in *non-dispatchable load* at its location , in accordance with sections 4.4.3.2, and 6.4.2.6; and

7.5.5.2 use any trade-off curves between *energy* and *operating reserves* in the *dispatch data* for that *registered facility* to determine an

appropriate adjustment in the quantity of *operating reserve* of each class supplied by the *registered facility*.

7.5.5A Section 7.5.5 shall not apply until such time that locational pricing is implemented in the *IESO-administered markets*.

7.5.6 If the *IESO* declares a *registered facility* other than a *boundary entity* to be non-conforming under section 7.5.4:

7.5.6.1 the *IESO* shall require the *registered market participant* for that *registered facility* to explain the reason for the non-compliance and shall record the response;

7.5.6.2 if the *IESO* determines that the *registered facility* is physically incapable of implementing the *dispatch instructions*, the *IESO* may require revision in the registration information for the non-conforming *registered facility*; and

7.5.6.3 if the *IESO* is not satisfied that the *registered facility* will respond to future *dispatch instructions*, the *IESO* may direct the *registered facility* to follow, as closely as practicable, an output or withdrawal profile specified by the *IESO*, and shall thereafter represent the *registered facility* as a *self-scheduling generation facility, self-scheduling electricity storage facility* or *non-dispatchable load* having the specified profile until the non-conforming *registered facility* satisfies the *IESO* that it has remedied the conditions causing the non-conformance.

7.5.7 Until the *registered market participant* for a non-conforming *registered facility* responds to the requirements of this section 7.5 to the satisfaction of the *IESO*, such *registered facility* shall continue to be designated as non-conforming, and such failure to respond on the part of that *registered market participant* may be referred by the *IESO* to the *market surveillance panel* at any time.

7.5.8 The *IESO* shall assume that a *registered facility* that is a *boundary entity* will comply fully with all *dispatch instructions* for *energy* or *operating reserves* upon confirmation of the relevant *interchange schedule* with the appropriate scheduling entity.

7.5.8A A *registered market participant* associated with a *registered facility* that is a *boundary entity* shall, other than for the bona fide and legitimate reasons referred to in section 7.5.8B, schedule *energy* and *operating reserve*, in accordance with section 6.1.3, with the appropriate scheduling entity, or scheduling entities as the case may be.

7.5.8B The *IESO* may take actions pursuant to section 6.6.10A of Chapter 3 and shall assess a real-time import or export failure charge as determined in section 3.8C of Chapter 9 where a *registered market participant* associated with a *registered facility* that is a *boundary entity* fails to schedule *energy* or *operating reserve*, in accordance with section 6.1.3 of Chapter 7, with the appropriate scheduling entity, or scheduling entities as the case may be, according to the applicable *interchange schedule*, other than for bona fide and legitimate reasons as determined by the *IESO.* Bona fide and legitimate reasons shall include failures caused by actions and circumstances beyond the control of the *market participant* or due to *IESO* or external scheduling entity error or action, including those reasons specified in the applicable *market manual*.

7.5.9 In addition to any other sanction or consequence provided for in these *market rules*, the *IESO* may disqualify from future participation in the *operating reserve market* any *registered facility* that consistently fails to increase *energy* generation or reduce *energy* withdrawal when called upon in accordance with Chapter 7.

7.6 Dispatch Scheduling Errors

7.6.1 A *dispatch scheduling error* shall be deemed to have occurred if either:

7.6.1.1 an *arbitrator* determines that the *IESO* has made a *dispatch scheduling error*; or

7.6.1.2 the *IESO* declares that it has made a *dispatch scheduling error*, on its own initiative, including pursuant to section 6.9 of Chapter 9 or further to a *notice of disagreement* filed or other *settlement* dispute initiated by a *market participant* pursuant to section 6.8 or 6.10 of Chapter 9.

7.6.2 When a *dispatch scheduling error* has occurred, the *IESO* shall not adjust *market prices* but shall, subject to section 7.6.3 and notwithstanding section 13.1.2 of Chapter 1, be strictly liable to compensate a *market participant* for damages suffered by the *market participant* as a result of the *dispatch scheduling error,* assessed in accordance with section 13.1.4 of Chapter 1.

7.6.3 A *market participant* that wishes to claim compensation pursuant to section 7.6.2 shall:

7.6.3.1 where the *dispatch scheduling error* was determined to have been made pursuant to section 7.6.1.1, request the *arbitrator* to determine the *market participant's* entitlement to and amount of, if any, such compensation; and

7.6.3.2 where the *dispatch scheduling error* was determined to have been made pursuant to section 7.6.1.2, request that the *IESO* determine the *market participant's* entitlement to and amount of, if any, such compensation,

with the amount, if any, in either case being determined in accordance with section 7.6.4.

7.6.4 Any amount determined by an *arbitrator* or by the *IESO,* as the case may be, pursuant to section 7.6.3 or 7.6.5 shall be assessed in accordance with section 13.1.4 of Chapter 1 and shall exclude such amount as may be required to account for any congestion management *settlement* credit triggered by the relevant *dispatch scheduling error* and already credited to the *market participant.*

7.6.5 If a *market participant* wishes to dispute a determination made by the *IESO* pursuant to section 7.6.3.2, it shall submit the matter to the dispute resolution process set forth in section 2 of Chapter 3 and shall, if the good faith negotiations referred to in section 2.4 of that Chapter fail to resolve the matter, request in the *notice of dispute* that the *arbitrator* determine the *market participant's* entitlement to the compensation referred to in section 7.6.2, the amount, if any, of such compensation or both, as the case may be.

7.7 Additional IESO Powers in Emergency and High-Risk Conditions

7.7.1 During real-time operations, the *IESO* is responsible for declaring an *emergency operating state* or a *high-risk operating state* under circumstances described in sections 2.3 and 2.4 of Chapter 5.

7.7.2 The *IESO*'s primary responsibility in an *emergency operating state* or a *high-risk operating state* is to preserve system *reliability*, with a secondary responsibility to restore normal system conditions and operation of the *IESO-administered markets* as soon as practicable.

7.7.3 Where an *emergency operating state* or a *high-risk operating state* has been declared, the *IESO* may implement any of the actions detailed in sections 2.3, 2.4, 5.8 and 5.9 of Chapter 5.

7.7.4 The *IESO* may determine any additional compensation payable in respect of *physical services* acquired during an *emergency operating state* or a *high-risk operating state*.

7.8 Publication of Real-Time Dispatch Information

7.8.1 The *IESO* shall, within one hour after each *dispatch hour*, *publish* information concerning system results and events during that *dispatch hour*. This information shall include, but is not limited to:

7.8.1.1 total load met;

7.8.1.2 transmission capacity between the *IESO-controlled grid* and each *intertie zone*;

7.8.1.3 subject to section 7.8.2, any *outages* of transmission *facilities*;

7.8.1.4 total *operating reserve* scheduled, and total *energy* called from such *operating reserve*, by area;

7.8.1.5 the market prices for each *dispatch interval*; and

7.8.1.6 the uniform *hourly Ontario energy price* (HOEP) determined in accordance with section 8.3.1.

7.8.2 Until the date that is the first day of the fourth calendar month following the *market commencement date,* calculated from the first day of the calendar month immediately following the month in which the *market commencement date* occurs, the *IESO* shall not *publish* information concerning *outages* of transmission *facilities* referred to in section 7.8.1.3.

8. Determining Market Prices

8.1 Purpose and Timing of Determining Market Prices

8.1.1 The *IESO* shall use the procedures in this section 8 to determine the uniform *market prices* in the *IESO control area* and the *intertie zone* prices for *energy* and *operating reserve* that are used for the market *settlement process* pursuant to the provisions of Chapter 9.

8.1.1A The *IESO* shall determine the *intertie congestion price* associated with each *intertie zone* for each *dispatch hour* based on the *pre-dispatch schedule* referred to in section 6.1.3.

8.1.2 Subject to section 8.4A, the *IESO* shall determine and *publish market prices* for *energy* and *operating reserve* in accordance with sections 8.2 and 8.3 within five minutes after the end of each *dispatch interval*, as provided in section 6.4.

8.1.2.1 [Intentionally left blank]

8.1.2.2 [Intentionally left blank]

8.1.2.3 [Intentionally left blank]

8.1.3 [Intentionally left blank]

8.2 Ex-post Prices for Each Dispatch Interval

8.2.1 The *IESO* shall determine *market prices* for *energy* and *operating reserve* for each *dispatch interval*, using the *dispatch algorithm* as follows:

8.2.1.1 the data and information described in section 4.4 shall be used as inputs, using the most recent valid *dispatch data* submitted by *registered market participants* and the most accurate system data and *metering data* for that *dispatch interval* that is available at the time the *market prices* are being determined;

8.2.1.2 the unconstrained *IESO-controlled grid* model shall be used;

8.2.1.3 the operating status of each *registered facility*, in the *dispatch algorithm* at the start of each *dispatch interval* shall be set equal to the operating status in the *market schedule* determined for the end of the preceding *dispatch interval* for that *registered facility* and, subject to section 8.2.3, recognizing by the adjustment to the input data any *registered facility* in respect of which a *forced outage* has occurred or of which the *interchange schedule* has been curtailed due to constraints external to the *IESO control area* during that *dispatch interval*;

8.2.1.4 the *dispatch algorithm* shall be run to determine *the market schedules* that maximise the economic gains from trade under the assumptions made pursuant to this section 8.2.1; and

8.2.1.5 subject to section 8.2.2, the marginal costs from the *dispatch algorithm* for *energy* and each class of *operating reserve*, in the *IESO control area* and in each *intertie zone*, shall be the *market prices* for that *dispatch interval*.

8.2.2 The prices produced as part of the output of the market scheduling and pricing process described in Appendix 7.5 for a pricing run shall not necessarily be the prices that are used for *settlement* purposes. Without limiting the generality of the foregoing, the following prices shall be used for *settlement* purposes:

8.2.2.1 the *energy* price for an *intertie zone* adjoining the *IESO control area* shall for *settlement* purposes, and subject to sections 8.2.2.4 to 8.2.2.7, equal the uniform Ontario *energy* price modified by the difference between the *intertie zone energy* price and the uniform Ontario *energy* price determined in the projected *market schedule*;

8.2.2.2 the *operating reserve* price for each class of *operating reserve* supplied from within the *IESO control area* shall for *settlement* purposes, and subject to sections 8.2.2.4 to 8.2.2.7, be formed:

a. from the shadow prices associated with the *operating reserve* requirements within the *IESO control area* during *dispatch intervals* when such requirements can be met; or

b. from the greater of the highest priced *offer* associated with the scheduled *operating reserve* or the *energy* prices for the *dispatch interval* during which the *operating reserve* requirements within the *IESO control area* cannot be met;

8.2.2.3 the *operating reserve* price for each class of *operating reserve* in an *intertie zone* adjoining the *IESO control area* shall for *settlement* purposes, and subject to section 8.2.2.4 to 8.2.2.7, equal the corresponding uniform *operating reserve* price for the *IESO control area* for that class of *operating reserve* modified by the difference between the corresponding *operating reserve* price for the *intertie zone* and the uniform *operating reserve* price for the *IESO control area* determined in the projected *market schedule*;

8.2.2.4 any *energy* price produced which exceeds *MMCP* shall be set equal to *MMCP* for *settlement* purposes;

8.2.2.5 any *energy* price produced which is less than negative *MMCP* shall be set equal to negative *MMCP* for *settlement* purposes;

8.2.2.6 any price for *operating reserve* produced which exceeds *MORP* shall be set equal to *MORP* for *settlement* purposes; and

8.2.2.7 any price for *operating reserve* produced which is negative will be set equal to zero for *settlement* purposes.

8.2.3 In the calculation of *market prices*, the *IESO* shall:

8.2.3.1 in the manner specified in section 8.2.1.3, adjust the input data at the start of a *dispatch interval* of a *registered facility* in respect of which a *forced outage* or *interchange schedule* curtailment due to constraints external to the *IESO control area* has occurred during the preceding or an earlier *dispatch interval*; and

8.2.3.2 make the adjustment referred to in section 8.2.1.3 in respect of such *registered facility* only to the extent that the input data can be adjusted having regard to the timing of the *forced outage* or *interchange schedule* curtailment due to constraints external to the *IESO control area* and the *IESO's* procedures for updating input data.

8.3 Uniform Ex-post Prices for Each Hour

8.3.1 The *IESO* shall determine, for each *dispatch hour*, a uniform *hourly Ontario energy price* (HOEP) in accordance with the formulation described as $HOEP_h$ in section 3.1.3 of Chapter 9.

8.4 [Intentionally left blank]

8.4A Administrative Pricing and Corresponding Schedules – Revised

8.4A.1 This section 8.4A applies only in respect of the establishment of *administrative prices* for the *real-time energy market* and the *operating reserve market.*

8.4A.2 The *IESO* shall establish *administrative prices* and, where applicable, corresponding *market schedules* when:

8.4A.2.1 the *energy market* or the *operating reserve market* has been suspended in accordance with section 13;

8.4A.2.2 the *IESO* is unable to *publish* an *energy market price* or *operating reserve market price* in accordance with section 8.1.2 due to a failure in or *planned outage* of the software, hardware or communications systems that supports the operation of the *dispatch algorithm*;

8.4A.2.3 the *IESO* determines, pursuant to guidelines approved by the *IESO Board* relating to price error materiality and acceptable causal

events, that a *published energy market price* or *operating reserve market price* is incorrect due to incorrect inputs which affected the outcome of the *dispatch algorithm*;

and all such *administrative prices* shall be the *energy market price* and the *operating reserve market price* for the applicable *dispatch interval* for all purposes under these *market rules*.

8.4A.3 Where the *IESO* establishes *administrative prices* pursuant to section 8.4A.2 it shall do so within two *business days* of the event causing *market prices* to be administered. The *IESO* shall inform *market participants* as soon as practicable whenever a *published market price* is an *administrative price*.

Administration of Prices Due to Failures or Planned Outages of Market Systems, Publication of Incorrect Prices or Implementation of an Emergency Control Action

8.4A.4 In circumstances where *administrative prices* are required under sections 8.4A.2.2, or 8.4A.2.3 the *IESO* shall establish *administrative prices* and corresponding *market schedules* that would, to the extent practical, reflect the *market prices* and corresponding *market schedules* that would have otherwise been produced by the *real-time markets*, but for the event causing *market prices* to be administered.

8.4A.5 Where the *IESO* establishes *administrative prices* pursuant to sections 8.4A.2.2, or 8.4A.2.3 in respect of one or more *dispatch intervals*, it shall use the best available *dispatch data* for *energy* or *operating reserve*, as the case may be, pertaining to the *dispatch interval* to which the *administrative price* is to be applied and the *market prices* and corresponding *market schedule* for that *dispatch interval* shall be as the *IESO* determines appropriate consistent with the principle stated in section 8.4A.4, and shall be the *market price* and corresponding *market schedule* from:

8.4A.5.1 the closest preceding *dispatch interval* that has not been administered, up to a maximum of 24 *dispatch intervals*;

8.4A.5.2 the closest subsequent *dispatch interval* that has not been administered, up to a maximum of 24 *dispatch intervals*; or

8.4A.5.3 a combination of the closest preceding and closest subsequent *dispatch intervals* that have not been administered, provided that neither the preceding nor subsequent *dispatch intervals* are selected for more than 24 *dispatch intervals* and are applied in a continuous manner such that the *administrative price* chosen from

the preceding *dispatch interval* shall apply until changed to the *administrative price* selected from the subsequent *dispatch interval*.

8.4A.6 Where the *IESO* establishes an *administrative price* pursuant to sections 8.4A.2.2, or 8.4A.2.3 the *IESO* shall, if the need for *administrative prices* extends beyond 48 *dispatch intervals*, establish *administrative prices* for the remaining *dispatch intervals* of the event causing *market prices* to be administered within the *IESO control area* and the *intertie zones,* using an average *HOEP* for the *energy market* and the hourly average of the *operating reserve* prices for the applicable *dispatch intervals* for the *operating reserve markets*, determined from the corresponding hour or hours from each of the 4 most recent *business days* or non-*business days*, as the case may be, excluding those hours from any day in which *administrative pricing* has been established under this section. Prices for the excluded hours shall be replaced by prices that have not been administered under this section from the corresponding hours of the most recent earlier *business days* or non-*business days*, as the case may be.

8.4A.7 Where the *IESO* establishes an *administrative price* for a *dispatch interval* pursuant to section 8.4A.6, there shall be no congestion management *settlement* credit payments made under section 3.5.2 of Chapter 9 for that *dispatch interval*.

Administration of Prices Due to Market Suspension

8.4A.8 Where the *IESO* establishes *administrative prices* during a market suspension pursuant to section 8.4A.2.1, it shall establish the *administrative price* as one of the following, as the *IESO* determines appropriate:

8.4A.8.1 where *market operations* have been suspended for reasons other than a failure in the software that generates *market prices* and operations of the *IESO-controlled grid* are based to some extent on market-based information and signals, a *market price* calculated using that software; or

8.4A.8.2 where operations of the *IESO-controlled grid* are being conducted without regard to the market, for the *IESO control area* and the *intertie zones,* an average *HOEP* for the *energy market* and the hourly average of the *operating reserve* prices for the applicable *dispatch intervals* for the *operating reserve markets*, determined from the corresponding hour or hours from each of the 4 most recent *business days* or non-*business days*, as the case may be, excluding those hours from any day in which *administrative pricing* has been established under this section, and there shall be no congestion management *settlement* credit payments made under

section 3.5.2 of Chapter 9 for the period of *market suspension*. Prices for the excluded hours shall be replaced by prices that have not been administered under this section from the corresponding hours of the most recent earlier *business days* or non-*business days*, as the case may be.

Additional Compensation for Complying with Dispatch Instructions

8.4A.9 Where the *IESO* has established an *administrative price* pursuant to sections 8.4A.6 and 8.4A.8.2 and subject to any materiality limits published in the applicable *market manual*,

8.4A.9.1 a *market participant* with a *generation facility* that has complied with *dispatch instructions* issued by the *IESO* shall be entitled to additional compensation determined under section 8.4A.10;

8.4A.9.2 a *market participant* with a *dispatchable load facility* shall be entitled to additional compensation on those consumption amounts where their *bid* price is less than the *administrative price,* equal to the difference between its applicable *bid* price and the *administrative price* multiplied by those consumption amounts if:

- the *market participant's bid* price, for the level of consumption to which it was dispatched, is less than the *administrative price;*
- the *market participant* has complied with *dispatch instructions* issued by the *IESO*; and
- the *market participant* issues to the *IESO* a *notice of disagreement* in accordance with section 6.8 of Chapter 9;

8.4A.9.3 a *market participant* with an *electricity storage facility* that injected *energy* into the *electricity system* shall be entitled to additional compensation on those injection amounts where its *offer* price is greater than the *administrative price*, equal to the difference between its applicable *offer* price and the *administrative price* multiplied by those injection amounts if;

- the *market participant's offer* price, for the level of injection to which it was dispatched, is greater than the *administrative price;*
- for the *dispatch hour,* where both *energy offers* and *bids* are submitted for the same *electricity storage facility*, these *energy*

offers and *bids* were submitted in accordance with section 21.4.2 of this Chapter;

- the market participant has complied with the dispatch instruction for the dispatch interval to which the administrative price applies; and
- the *market participant* issues to the *IESO* a *notice of disagreement* in accordance with section 6.8 of Chapter 9; and

8.4A.9.4 a *market participant* with an *electricity storage facility* that withdrew *energy* from the *electricity system* shall be entitled to additional compensation on those withdrawal amounts where its *bid* price is less than the *administrative price*, equal to the difference between its applicable *bid* price and the *administrative price* multiplied by those consumption amounts if:

- the *market participant's bid* price, for the level of withdraws to which it was dispatched, is less than the *administrative price;*
- for the *dispatch hour,* where both *energy offers* and *bids* are submitted for the same *electricity storage facility*, these *energy offers* and *bids* were submitted in accordance with section 21.4.2 of this Chapter;
- the market participant has complied with the dispatch instruction for the dispatch interval to which the administrative price applies; and
- the *market participant* issues to the *IESO* a *notice of disagreement* in accordance with section 6.8 of Chapter 9;

and the *IESO* shall recover any such compensation amounts in accordance with section 4.8 of Chapter 9.

8.4A.9A If the *energy market* is suspended and no *bid* prices are available to make the determination in section 8.4A.9.2 that a *bid* price is less than the *administrative price*, a *market participant* with a *dispatchable load facility* shall provide to the *IESO* evidence that its average historical *bid* price is less than the *administrative price*. Average historical *bid* prices shall be determined for each interval from the corresponding interval from each of the four most recent *business days* or non-*business days*, as the case may be, prior to the event that gave rise to the *administrative price*.

8.4A.9B If the *energy market* is suspended and no *offer* prices are available to make the determination in section 8.4A.9.3 that an *offer* price is greater than the *administrative price*, a *market participant* with an *electricity storage facility* shall provide to the *IESO* evidence that its average historical *offer* price is greater than the *administrative price*. Average historical *offer* prices shall be determined for each interval from the corresponding interval from each of the four most recent *business days* or non-*business days*, as the case may be, prior to the event that gave rise to the *administrative price*.

8.4A.9C If the *energy market* is suspended and no *bid* prices are available to make the determination in section 8.4A.9.4 that a *bid* price is less than the *administrative price*, a *market participant* with an *electricity storage facility* shall provide to the *IESO* evidence that its average historical *bid* price is less than the *administrative price*. Average historical *bid* prices shall be determined for each interval from the corresponding interval from each of the four most recent *business days* or non-*business days*, as the case may be, prior to the event that gave rise to the *administrative price*.

Dispatchable Generator, Electricity Storage Facility while Injecting, and Import:

$$\text{Compensation} = (-1) * OP(EMP_h^{m,t^*}, AQEI_{k,h}^{m,t^*}, BE)$$

Where:

t* = *metering interval* of administrative price period

EMP_h^{m,t^*} is the administrative price in the metering interval t* of settlement hour h

OP is the profit function as described in Chapter 9, Section 3.5.2

Dispatchable Load, Electricity Storage Facility while Withdrawing and Export:

$$\text{Compensation} = OP(EMP_h^{m,t^*}, AQEW_{k,h}^{m,t^*}, BL)$$

Where:

t* = *metering interval* of administrative price period

EMP_h^{m,t^*} is the administrative price in the metering interval t* of settlement hour h

OP is the profit function as described in Chapter 9, Section 3.5.2

8.4A.10 The compensation referred to in section 8.4A.9.1 shall be calculated as the aggregate of:

8.4A.10.1 the fuel costs or, where applicable, the other costs referred to in section 8.4A.11, and the variable operating and maintenance costs incurred by the *market participant* in complying with the *dispatch instructions* issued by the *IESO,* which fuel costs or other costs and variable operating and maintenance costs shall be subject to verification and audit by the *IESO*; and

8.4A.10.2 subject to section 8.4A.11, an amount equal to 10% of the amount determined pursuant to section 8.4A.10.1,

less the amount of the *administrative price* already paid or payable to the *market participant* under sections 8.4A.6 and 8.4A.8.2.

8.4A.11 Where the compensation referred to in sections 8.4A.9.1 relates to a *generation facility* that is energy limited by design or by bona fide contractual commitments, the *IESO* may accept, in lieu of the costs referred to in section 8.4A.10.1, such assessment of the expected future value or the opportunity costs of the fuel or water consumed:

8.4A.11.1 during the period while *administrative prices* were in effect; and

8.4A.11.2 in order to comply with the *dispatch instruction* issued by the *IESO*;

as the *IESO* considers reasonable. Where such value or costs are submitted in lieu of the costs referred to in section 8.4A.10.1, no amount shall be payable pursuant to section 8.4A.10.2 if, in the *IESO's* opinion, such value or costs include or adequately cover such amount.

Settlement Amount Adjustments Resulting from Administration of Prices Due to Failures or Planned Outages of Market Systems or Due to Publication of Incorrect Prices

8.4A.13 Where the *IESO* has established an *administrative price* pursuant to section 8.4A.5, a *market participant* may, subject to any materiality limits published in the applicable *market manual*, be eligible for an adjustment to its *settlement amounts* if:

8.4A.13.1 that *market participant* has been assessed a negative hourly congestion management *settlement* credit pursuant to section 3.5 of Chapter 9 for any of the applicable *dispatch intervals*;

8.4A.13.2 no *intertie* offer guarantee that would offset that negative hourly congestion management *settlement* credit has been assessed for that *market participant* pursuant to section 3.8A of Chapter 9;

8.4A.13.3 the *market schedule* determined pursuant to section 8.4A.5 is carried forward or backward to another *dispatch hour* that is the *dispatch hour* to which the negative congestion management *settlement* credit referred to in section 8.4A.13.1 applies;

8.4A.13.4 the price and/or quantity values in the *dispatch data* submitted by the *market participant* are different in the *dispatch hour* from which the *market schedule* referred to in section 8.4A.13.3 was established compared to the *dispatch data* submitted by the *market participant* for the *dispatch hour* to which the negative congestion management *settlement* credit referred to in section 8.4A.13.1 applies;

8.4A.13.5 the *market participant* complied with the *dispatch instructions* issued by the *IESO* for the applicable *dispatch intervals*;

8.4A.13.6 the negative hourly congestion management *settlement* credit referred to in section 8.4A.13.1 arose strictly due to the circumstances outlined in section 8.4A.13.3 through 8.4A.13.5; and

8.4A.13.7 the *market participant* issues to the *IESO* a *notice of disagreement* in accordance with section 6.8 of Chapter 9 providing evidence that the circumstances outlined in section 8.4A.13.1 through 8.4A.13.6 have occurred.

8.4A.14 If the *market participant*, pursuant to section 8.4A.13, has demonstrated to the satisfaction of the *IESO* that circumstances outlined in section 8.4A.13.1 through 8.4A.13.6 have occurred, the *IESO* shall, in accordance with section 6.6 of Chapter 9, adjust the *market participant's settlement amounts* by an amount to offset the negative hourly congestion management *settlement* credit referred to in section 8.4A.13.1.

8.4A.15 Where the *IESO* has established an *administrative price* pursuant to section 8.4A.5, a *market participant* may, subject to any materiality limits published in the applicable *market manual*, be eligible for additional compensation if:

8.4A.15.1 the *market participant* has been assessed an hourly net *energy market settlement* credit for a *dispatchable facility* or *boundary entity* that represents either an underpayment or overcharge, as the case may be, when comparing the *administrative price* used for determining the hourly net *energy market settlement* credit to the *market participant's* applicable *offer* or *bid* price;

8.4A.15.2 no *intertie* offer guarantee that would offset that underpayment has been assessed for that *market participant* pursuant to section 3.8A of Chapter 9;

8.4A.15.3 no hourly congestion management *settlement* credit that would offset that overcharge or underpayment has been assessed for that *market participant* pursuant to section 3.5 of chapter 9;

8.4A.15.4 the *market schedule* determined pursuant to section 8.4A.5 is carried forward or backward to another *dispatch hour* that is the *dispatch hour* to which the hourly net *energy market settlement* credit referred to in section 8.4A.15.1 applies;

8.4A.15.5 the price and/or quantity values in the *dispatch data* submitted by the *market participant* are different in the *dispatch hour* from which the *market schedule* referred to in section 8.4A.15.4 was established compared to the *dispatch data* submitted by the *market participant* for the *dispatch hour* to which the above hourly net *energy market settlement* credit applies referred to in section 8.4A.15.1;

8.4A.15.6 the *market participant* complied with the *dispatch instructions* issued by the *IESO* for the applicable *dispatch intervals*;

8.4A.15.7 the hourly net *energy market settlement* credit referred to in section 8.4A.15.1 and the resulting overcharge or underpayment arose strictly due to the circumstances outlined in section 8.4A.15.4 through 8.4A.15.6; and

8.4A.15.8 the *market participant* issues to the *IESO* a *notice of disagreement* in accordance with section 6.8 of Chapter 9 providing evidence that the circumstances outlined in section 8.4A.15.1 through 8.4A.15.7 have occurred.

8.4A.16 If the *market participant*, pursuant to section 8.4A.15 has demonstrated to the satisfaction of the *IESO* that circumstances outlined in section 8.4A.15.1 through 8.4A.15.7 have occurred, the *IESO* shall, in accordance with section 6.8 of

Chapter 9, adjust the *market participant's settlement amounts* by the following amount to offset the overcharge or underpayment, referred to in section 8.4A.15.1, as the case may be.

Dispatchable Generator and Import:

Compensation = (-1) * OP(EMP_h^{m,t^*}, $AQEI_{k,h}^{m,t^*}$, BE)

Where:

t* = *metering interval* of administrative price period

EMP_h^{m,t^*} is the administrative price in the metering interval t* of settlement hour h

OP is the profit function as described in Chapter 9, Section 3.5.2

Dispatchable Load and Export:

Compensation = OP(EMP_h^{m,t^*}, $AQEW_{k,h}^{m,t^*}$, BL)

Where:

t* = *metering interval* of administrative price period

EMP_h^{m,t^*} is the administrative price in the metering interval t* of settlement hour h

OP is the profit function as described in Chapter 9, Section 3.5.2

Conditions to Cease the Administration of Prices

8.4A.17 The *IESO* shall cease to apply *administrative prices*:

8.4A.17.1 where section 8.4A.2.1 applies, from the commencement of the first *dispatch interval* in the *dispatch hour* referred to in section 13.7.1.2;

8.4A.17.2 where section 8.4A.2.2 applies due to a failure in software, hardware or communications systems, from the commencement of the first *dispatch interval* after the failure referred to in that section has been rectified;

8.4A.17.3 where section 8.4A.2.2 applies due to a *planned outage* of software, hardware or communications systems, from the commencement of the first *dispatch interval* after the *planned outage* referred to in that section has been completed; and

8.4A.17.4 where section 8.4A.2.3 applies, from the commencement of the first *dispatch interval* after the incorrect inputs referred to in that section have been corrected.

9. IESO Procurement Markets

9.1 Introduction

9.1.1 The *IESO* shall procure, primarily through contracts, certain *physical services* that are needed to maintain *reliable* system operations but that are not offered in the *real-time markets*. The *IESO* may also enter into contracts allowing it to direct the operations of specific *generation facilities, electricity storage facilities* or *load facilities* that are critical to system *reliability* under certain conditions. This section 9 describes such *physical services* and the manner in which the *IESO* shall procure them.

9.2 Definition of Contracted Ancillary Services

9.2.1 Subject to sections 9.4 and 9.5.2, the *IESO* shall procure *contracted ancillary services* through contracts between the *IESO* and *ancillary service providers* that are *registered market participants* who have demonstrated the ability to provide such *contracted ancillary services* from *registered facilities* in accordance with the performance standards and other applicable requirements of section 4 of Chapter 5. *Contracted ancillary services* shall meet all applicable standards set forth in section 4 of Chapter 5 and shall be procured such as to enable the *IESO* to meet its obligations thereunder.

9.2.2 The principal *contracted ancillary services* that the *IESO* will procure pursuant to section 9.2.1 are:

9.2.2.1 *regulation*: this *ancillary service* allows total system generation to match total system load (plus losses) minute-by-minute or even second-by-second as required on an electricity grid;

9.2.2.2 *voltage control* and *reactive support*: this *ancillary service* involves the control and maintenance of prescribed voltages at

specific locations, using defined reactive capacity, *energy* and manoeuvrability to support system operations. *Reactive support* is provided by *generation units, electricity storage units* as well as by synchronous condensers, capacitors and other electrostatic equipment that is often owned and operated by *transmitters*; and

9.2.2.3 *black start capability*: this *ancillary service* involves *generation facilities* that are tested and/or assessed for their ability to be a *certified black start facility*, and from which the *IESO* may direct the delivery of power without assistance from the electrical system.

9.2.2.4 [Intentionally left blank – section deleted]

9.2.3 The IESO shall procure each contracted ancillary service:

9.2.3.1 in sufficient quantities and at the appropriate locations to enable the *IESO* to meet its obligations under Chapter 5 to ensure *reliable* operation of the *electricity system*, in accordance with all applicable *reliability standards*; and

9.2.3.2 using, to the extent practicable, competitive processes appropriate to the specific technical and market characteristics of each *contracted ancillary service*, to acquire each *contracted ancillary service* at competitively determined prices.

9.3 Contracted Ancillary Service Contracts

9.3.1 The *IESO* shall enter into *contracted ancillary service* contracts with *ancillary service providers*. Such agreements shall, subject to sections 9.3.4 and 9.3.6:

9.3.1.1 [Intentionally left blank – section deleted]

9.3.1.2 compensate any *ancillary service provider* for levels of service above those required to be provided by the *connection* requirements of Chapter 4.

9.3.2 Subject to section 9.3.6, the *IESO* shall use one or a combination of the following processes to conclude *contracted ancillary service* contracts with *ancillary service providers*:

9.3.2.1 where practical, the *IESO* shall employ a competitive tendering or negotiation process to identify multiple potential *ancillary service providers* and to determine competitive prices and other terms for the *contracted ancillary service* contracts; or

9.3.2.2 the *IESO* may negotiate *contracted ancillary service* contracts with a single potential *ancillary service provider* where the *IESO* determines that this will result in reasonable prices and other terms.

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9.3.3.3 [Intentionally left blank]

9.3.4 The provisions of sections 9.3.1 and 9.5.1 shall be subject to any contrary provisions contained in:

9.3.4.1 any *licence*; or

9.3.4.2 the terms of any *contracted ancillary service* contract the terms of which are required by a *licence* to be, and have been, approved by the *Ontario Energy Board*.

9.3.5 Each person that:

9.3.5.1 has entered into a *contracted ancillary service* contract with the *IESO*; and

9.3.5.2 is not, at any time during the term of such *contracted ancillary service* contract, the r*egistered market participant* for that *facility*,

shall ensure that the *registered market participant* for that *facility* complies with the provisions of the *contracted ancillary service* contract.

9.3.6 Where the *IESO* and the *ancillary service provider* are unable to reach agreement upon the terms and condition of a proposed *ancillary service* contract, or an amendment to an *ancillary service* contract, the matter shall be determined by the *Ontario Energy Board*.

9.4 The Effect of Grid Connection Requirements

9.4.1 The *IESO* may at any time direct a *registered facility* to provide the level of any *ancillary service* that the *registered facility* is required to provide as a condition of any *licence* or as a result of any *connection* requirements provided for in Chapter 4.

9.4.2 Subject to section 9.4.4, a *registered facility* shall not be entitled to compensation from the *IESO* for any *ancillary service* that must be provided pursuant to the *connection* requirements provided for in Chapter 4 unless and until the *IESO* develops a market for such *ancillary service* that pays all providers of the *ancillary service* and/or that requires any *registered facility* to pay for the failure to supply up to some standard that may be less than that attributable to the *connection* requirement.

9.4.3 If the *IESO* directs a *registered facility* to provide a level of any *ancillary service* above the levels required by the *licence* applicable to that *registered facility* or any connection requirements provided for in Chapter 4 and the *registered facility* is not otherwise subject to a *contracted ancillary service* contract with the *IESO*, the *IESO* shall compensate the *registered facility* for any costs, including lost opportunity costs, incurred by the *registered facility* in complying with the *IESO*'s direction.

9.4.4 If the *IESO* directs a *registered facility* to provide *reactive support* within the range required by the *connection* requirements provided for in Chapter 4, the *IESO* shall only be required to compensate the *registered facility* to the extent that the *registered facility* incurs additional costs, provided that such additional costs are demonstrated to the satisfaction of the *IESO* to have been incurred in order to comply with the *IESO's* direction.

9.4.5 If the *IESO* directs a *registered facility* to provide *reactive support* within the range required by the *connection* requirements provided for in Chapter 4 or as stipulated in the applicable *contracted ancillary service* contract, and that *registered facility* has to reduce its active power output in order to comply with the *IESO*'s direction, that *registered facility* shall not be entitled to a congestion management *settlement* credit for that reduction in active power output.

9.5 Payment for Ancillary Services and Recovery of Costs

9.5.1 Subject to sections 9.3.4 and 9.3.6, the price payable by the *IESO* under a *contracted ancillary service* contract may cover any of the following:

9.5.1.1 the cost of being available to provide a *contracted ancillary service* if instructed by the *IESO* to do so;

9.5.1.2 the out-of-pocket costs and the opportunity costs of actually providing the *contracted ancillary service* when instructed by the *IESO* to do so; and

9.5.1.3 such other compensation as the *IESO* determines to be fair and reasonable under the circumstances.

9.5.2 The *IESO* is authorised, when necessary to maintain system *reliability* or when the *IESO-controlled grid* is in an *emergency operating state* to direct a *registered facility* to provide any class of *contracted ancillary services* even though the *IESO* does not have a *contracted ancillary service* contract with that *registered facility*. When this occurs:

9.5.2.1 the *IESO* shall compensate the *registered facility* for any costs, including opportunity costs, it incurs in complying with the *IESO's* direction; and

9.5.2.2 any dispute about the compensation payable pursuant to section 9.5.2.1 shall be resolved using the dispute resolution process set forth in section 2 of Chapter 3.

9.5.3 The *IESO* shall, in accordance with section 4.2 of Chapter 9, recover from *market participants* any costs it incurs in procuring *ancillary services*.

9.6 Definition and Principles of Must-Run Contracts

9.6.1 The *IESO* may, under the conditions and in accordance with the processes specified in this section 9.6, enter into a *reliability must-run contract* with the *registered market participant* or the prospective *registered market participant* for a *reliability must-run resource.* Where the *IESO* and a *registered market participant* or prospective *registered market participant* enter into a *reliability must-run contract* with respect to a given *reliability must-run resource*, the *IESO* may direct that *reliability must-run resource* to operate in specific ways when instructed by the *IESO* to do so for reasons of *reliability*, other than for reasons of a lack of overall *adequacy* of the *IESO-controlled grid*, regardless of whether *dispatch data* has been submitted with respect to that *reliability must-run resource*. Nothing in this section shall be construed as preventing the *IESO* from taking such other action in respect of such *reliability must-run resource* as may be permitted by these *market rules* to address a concern for overall *adequacy.*

9.6.2 Subject to section 9.6.4, the *IESO* may enter into a *reliability must-run contract* based on studies performed by the *IESO* that indicate:

9.6.2.1 in accordance with section 9.6.3, that a *reliability must-run resource* is required to be available for the purposes of *reliability*, other than in situations of overall *adequacy* of the *IESO-controlled grid*; or

9.6.2.2 a *reliability must-run resource* is likely to be *dispatched* as a *constrained on facility* or a *constrained off facility* and that such a contract would avail to the mutual benefit of the parties.

9.6.3 The studies referred to in section 9.6.2.1 shall include a consideration of whether concerns regarding *reliability*, other than regarding a lack of overall *adequacy* of the *IESO-controlled grid*, can be addressed by means of the process for directing the submission of *dispatch data* or for imposing a restriction on the revision of *dispatch data* referred to in sections 3.3.10 to 3.3.17 or of the process by which the *IESO* approves *outages* pursuant to section 6 of Chapter 5.

9.6.4 The IESO shall enter into a reliability must-run contract pursuant to section 9.6.2.2 in respect of a reliability must-run resource only where the registered market participant or the prospective registered market participant for the reliability must-run resource so agrees.

9.6.5 Where:

9.6.5.1 the *IESO* would be required to reject, revoke *advance approval* of, or recall the *planned outage* of a *registered facility* pursuant to section 6 of Chapter 5 but for the availability of a *reliability must-run resource*; and

9.6.5.2 the *reliability must-run resource* referred to in section 9.6.5.1 has planned a temporary reduction in staff that would restrict or prevent operation of that other *registered facility,*

the *IESO* may enter into a *reliability must-run contract* in respect of the *reliability must-run resource* referred to in section 9.6.5.1 provided that:

9.6.5.3 staffing adequate to permit that *reliability must-run resource* to operate under the *reliability must-run contract* can be arranged by that *reliability must-run resource* within the time required; and

9.6.5.4 the conclusion of the *reliability must-run contract* referred to in section 9.6.5.3 would avoid the need for the *IESO* to reject, revoke *advance approval* of, or recall the *planned outage* referred to in section 9.6.5.1.

9.6.6 The *IESO* may call upon a *reliability must-run resource* that is subject to a *reliability must-run contract* if and only if the *IESO* determines that *market participants* will not offer sufficient *physical services* into the *real-time markets* to enable the *IESO* to maintain *reliability*, other than in respect of a lack of overall *adequacy* of the *IESO-controlled grid*.

9.6.7 Subject to section 9.6.13, the *IESO* shall use one or a combination of the following processes to conclude *reliability must-run contracts* pursuant to section 9.6.2:

9.6.7.1 where practical, the *IESO* shall employ a competitive tendering or negotiation process to identify multiple potential suppliers and to determine competitive prices and other terms for the *reliability must-run contract*; or

9.6.7.2 the *IESO* may negotiate *reliability must-run contracts* with a single potential supplier where the *IESO* determines that this will result in reasonable prices and other terms.

9.6.8 Subject to sections 9.6.11 and 9.6.13:

9.6.8.1 the *IESO* may develop standard forms of *reliability must-run contracts* for use in conjunction with sections 9.6 and 9.7,

provided that

9.6.8.2 a standard form *reliability must-run contract* developed for use in conjunction with a *reliability must-run resource* that has planned a temporary reduction in staff that would restrict or prevent its operation, including but not limited to the circumstances described in section 9.6.5, shall provide compensation only for the out-of-pocket costs including, but not limited to, the costs of providing adequate staffing, incurred solely to permit the *reliability must-run resource* to be prepared to provide *physical services* if *dispatched* to do so, but no such compensation shall be payable in respect of *dispatch intervals* when the *reliability must-run resource* is *dispatched* to provide such *physical services* and is entitled to payment therefore as a result of such dispatch.

9.6.9 Subject to sections 9.6.11 and 9.6.13, the *IESO* may include in any *reliability must-run contract,* other than a standard form *reliability must-run contract* referred to in section 9.6.8.2, the compensation provisions referred to in section 9.6.8.2 or such other compensation provisions as the *IESO* determines appropriate.

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9.6.11 The provisions of sections 9.6.8, 9.6.9 and 9.7.1 shall be subject to any contrary provisions contained in:

9.6.11.1 any *licence*; or

9.6.11.2 the terms of any *reliability must-run contract* the terms of which are required by a *licence* to be, and have been, approved by the *Ontario Energy Board*.

9.6.12 [Intentionally left blank]

9.6.12.1 [Intentionally left blank]

9.6.12.2 [Intentionally left blank]

9.6.13 Where the *IESO* and the *registered market participant* or prospective *registered market participant* are unable to reach agreement upon the terms and condition of a *proposed reliability must-run contract*, or an amendment to a *reliability must-run contract*, the matter shall be determined by the *Ontario Energy Board*.

9.7 Terms and Conditions of Must-Run Contracts

9.7.1 Subject to sections 9.6.11 and 9.6.13, the *IESO* shall include in each *reliability must-run contract* terms and conditions that address, at a minimum, the following:

9.7.1.1 the duration of the *reliability must-run contract*, which shall not exceed 1 year;

9.7.1.2 the situations in which the *reliability must-run resources* may be called;

9.7.1.3 the situations under which some or all of the terms of the *reliability must-run contract* may be suspended;

9.7.1.4 the nature and timing of any advance notice required for the *IESO* to call upon the *reliability must-run resources*;

9.7.1.5 payment terms, including the amount and timing of any availability payment;

9.7.1.6 agreed *dispatch data* that the *IESO* shall use to *dispatch* the *reliability must-run resource* when it is called by the *IESO* to operate in various modes under the *reliability must-run contract*,

and provisions for the revision of such *dispatch data*, when necessary;

9.7.1.7 the process for amending the terms of the *reliability must-run contract*; and

9.7.1.8 any penalties payable by either party for failure to satisfy its obligations under the *reliability must-run contract*.

9.7.2 The *IESO* shall, in accordance with section 4.2 of Chapter 9, recover through charges on *market participants* the incremental costs of its *reliability must-run contracts* above any normal payments for *energy* and *operating reserves* recovered in the *real-time markets.*

9.8 Publication of Procurement Contract Information

9.8.1 The *IESO* shall treat information relating to the procurement of *contracted ancillary services* and *reliability must-run contracts* as follows:

9.8.1.1 the *IESO* shall *publish* annually the total costs of all contracted *ancillary services* subject to contracted *ancillary service* contracts and of all *reliability must-run contracts*;

9.8.1.2 the *IESO* shall *publish* annually the quantities of each *contracted ancillary service* covered under *contracted ancillary service* contracts and the quantities of each *physical service* provided under *reliability must-run contracts*, together with estimates of any additional quantities the *IESO* expects to acquire during the next 12 months;

9.8.1.3 where the *IESO* obtains *contracted ancillary services* or *reliability must-run contracts* in the absence of market power, the commercial terms of the *contracted ancillary service* contracts and of the *reliability must-run contracts* shall be treated as *confidential information*; and

9.8.1.4 where the *IESO* obtains *contracted ancillary services* or *reliability must-run contracts* in the presence of market power, as confirmed by the *market surveillance panel*, the *IESO* shall *publish* the relevant terms and conditions of the contracts, except for price which shall not be disclosed, in order to encourage competition.

9.9 Dispute Resolution

9.9.1 Subject to the *licence* of the *IESO* and of the relevant *market participant*, all disputes arising pursuant to a *contracted ancillary services* contract or a *reliability must-run contract* shall be resolved using the dispute resolution process set forth in section 2 of Chapter 3.

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11. Generator and Electricity Storage Participant Synchronization Procedures

11.1 Introduction

11.1.1 No generator or electricity storage participant:

11.1.1.1 may physically *connect* and synchronize to the *IESO-controlled grid* or de-synchronize and *disconnect* from the *IESO-controlled grid*; or

11.1.1.2 if an *embedded generator* or *embedded electricity storage participant* may physically *connect* and synchronize to the embedding *facility* or de-synchronize and *disconnect* from the embedding *facility*,

except as provided in Chapter 4 and in this section 11.

11.1.2 All *generation facilities* located within the *IESO control area* are subject to the provisions of this section 11 except for *self-scheduling generation facilities* with name-plate ratings of less than 10 MW, *intermittent generators*, any *generators* classified as *minor generation facilities* or as *small generation facilities, generation facilities* that, for the purposes of the application of the provisions of this section 11, have been designated by the *IESO* as not impairing the ability of the *IESO* to maintain the *security* or adequacy of the electricity system, and any *generators* exempt from the provisions of the *Electricity Act, 1998* by regulation made thereunder.

11.1.3 [Intentionally left blank]

11.1.4 All *electricity storage facilities* located within the *IESO control area* are subject to the provisions of this section 11 except for *self-scheduling electricity storage facilities* with an *electricity storage facility* size of less than 10 MW, any *electricity storage facilities* classified as *minor electricity storage facilities* or as *small electricity storage facilities*, *electricity storage facilities* that, for the purposes of the application of the provisions of this section 11, have been designated by the *IESO* as not impairing the ability of the *IESO* to maintain the *security* or adequacy of the electricity system.

11.2 Process for Synchronization

11.2.1 A *generator* or *electricity storage participant* that intends to synchronize a *generation unit* or *electricity storage unit* to the *IESO-controlled grid* or embedding *facility*, as the case may be, must notify the *IESO* at least two hours in advance of the intended synchronization time unless an under-generation advisory notice is in force, in which case the *IESO* may reduce the required notification time to that specified in the advisory notice.

11.2.2 If a *generator* or *electricity storage participant* does not advise the *IESO* at least two hours in advance of synchronization, or any shorter interval allowed by an under-generation advisory notice, the *IESO* may approve synchronization only if, in the *IESO*'s judgement, synchronization will not impair the ability of the *IESO* to maintain the *security* or *adequacy* of the *electricity system*.

11.2.3 The *IESO* shall notify the *generator* or *electricity storage participant* of the *IESO*'s acceptance or rejection of the *generation unit's* or *electricity storage unit's* synchronization plans within 5 minutes of receiving such plans. In the event that the *IESO* does not approve synchronization, the *registered market participant* responsible for the *registered facility,* of which the *generation unit* or *electricity storage unit* is a part, must revise its *dispatch data* in accordance with section 3.

11.2.4 Receipt by the *generator* or *electricity storage participant* of notification of acceptance by the *IESO* under section 11.2.3 gives the *generator* or *electricity storage participant* the right to synchronize the *generation unit* or *electricity storage unit* to the *IESO-controlled grid* or the embedding *facility*, as the case may be. This right does not preclude the *IESO* from requiring de-synchronization of a *generation unit* or *electricity storage unit* in the event of over-generation in accordance with any applicable provisions of these *market rules* relating to over-generation.

11.2.5 The exact time of synchronization shall be subject to directions from the *IESO* and to the terms and conditions specified in the *generator's* or *electricity storage participant's connection agreement* or, in the case of an *embedded generation unit* or *embedded electricity storage unit* its connection agreement, in such form as may be prescribed by the *OEB*, with the *distributor* with whom it is *connected.*

11.2.6 Each *generator* or *electricity storage participant* shall notify the *IESO* of any revisions to its synchronization plans without delay. Upon receipt of such notice, the *IESO* shall re-assess any prior acceptance of a synchronization plan and shall notify the *generator* or *electricity storage participant* accordingly.

11.3 Process for De-synchronization

11.3.1 A *generator* or *electricity storage participant* intending to de-synchronize a *generation unit* or *electricity storage unit* from the *IESO-controlled grid* or embedding *facility*, as the case may be shall notify the *IESO* one hour in advance of the intended de-synchronization time, unless an advisory notice for over-generation is in effect, in which event the *generation unit* or *electricity storage unit* may de-synchronize at will subject to the conditions of the advisory notice.

11.3.2 If a *generator* or *electricity storage participant* does not advise the *IESO* at least one hour prior to its planned de-synchronization, or any shorter interval allowed by an over-generation advisory notice, the *IESO* may approve de-synchronization only if, in the *IESO*'s judgement, the unit's de-synchronization will not impair the ability of the *IESO* to maintain the *security* or *adequacy* of the *electricity system*.

11.3.3 The *IESO* shall approve any request to de-synchronize unless:

11.3.3.1 the *generation unit* or *electricity storage unit* is operating under the provisions of a *reliability must-run contract* and the *IESO* has directed it to operate;

11.3.3.2 the *IESO* requires the *generation unit* or *electricity storage unit* to remain synchronized to maintain the *security* or *adequacy* of the *electricity system*; or

11.3.3.3 an under-generation advisory notice is in force.

11.3.4 The *IESO* shall notify the *generator* or *electricity storage participant* of the *IESO*'s acceptance or rejection of the *generation unit's or electricity storage unit's* de-synchronization plans within 5 minutes of receiving such plans.

11.3.5 The exact time of de-synchronization shall be subject to directions from the *IESO* and to the terms and conditions specified in the *generator's* or *electricity storage participant's connection agreement* or, in the case of an *embedded generation unit*, or *embedded electricity storage unit* its connection agreement, in such form as may be prescribed by the *OEB*, with the *distributor* with whom it is *connected.*

11.3.6 Receipt by the *generator* or *electricity storage participant* of notification of acceptance by the *IESO* under section 11.3.4 gives the *generator* or *electricity storage participant* the right to commence shut-down of the *generation unit* or *electricity storage unit*.

11.3.7 Each *generator* or *electricity storage participant* shall notify the *IESO* of any revisions to its de-synchronization plans without delay. Upon receipt of such

notice, the *IESO* shall re-assess any prior acceptance of a de-synchronization plan and shall notify the *generator* or *electricity storage participant* accordingly.

12. Status Reports, Advisories, and Protocols

12.1 IESO System Status Reports and Advisory Notices

12.1.1 The *IESO* shall *publish*, in addition to the daily assessments specified in section 7.3.1.4 of Chapter 5, system status reports to:

12.1.1.1 to 12.1.1.5 [Intentionally left blank – sections deleted]

12.1.1.6 provide forecasts, with respect to each *dispatch day*, as projected for future *dispatch hours* and as estimated for the current *dispatch hour*, where appropriate, of expected hourly *demand*, *generation capacity*, *electricity storage capacity*, *energy* capability of *generation facilities*, exports and imports of *energy*, and *operating reserve* requirements, *published* at the following times:

12.1.1.6.1 05:30 EST of the *pre-dispatch day*;

12.1.1.6.2 09:00 EST of the *pre-dispatch day*;

12.1.1.6.3 after each successful run of the day-ahead commitment process, of the *pre-dispatch day*;

12.1.1.6.4 after 15:00 EST, and hourly thereafter, of the *pre-dispatch day*; and

12.1.1.6.5 hourly on the *dispatch day;*

12.1.1.7 provide forecasts of expected transmission capacity with all elements in-service, *published* daily, as soon as practicable; and

12.1.1.8 provide forecasts of expected transmission limits with *outages*, for the *dispatch day* and the two days following the *dispatch day*, *published* hourly on the *dispatch day.*

12.1.2 Where the *IESO publishes* an advisory notice, it shall do so in one of the following forms, in accordance with the applicable *market manual*:

12.1.2.1 an alert notice, which shall provide situational awareness and provide time for advanced preparations;

12.1.2.2 a warning notice, which shall indicate the actions the *IESO* intends to take if the *IESO-administered markets* do not or cannot respond sufficiently to eliminate an identified or potential problem; or

12.1.2.3 an action notice, which shall indicate the actions the *IESO* and *market participants* must take in order to eliminate an identified or potential problem.

12.1.3 The *IESO* shall *publish*, in accordance with the applicable *market manual*, advisory notices for the following reasons:

12.1.3.1 if a major change in expected *generation capacity, electricity storage capacity* or *transmission capacity* has occurred since the last system status report was issued;

12.1.3.2 if the *IESO* expects over-generation, under-generation or shortfalls in *operating reserve* or *contracted ancillary services*, or an advisory of the total MW of *energy* being directed to submit *bids* or *offers* from the aggregate of *reliability must run resources* under *reliability must run contracts*;

12.1.3.3 if the IESO expects an emergency operating state, a high-risk operating state, or a conservative operating state; and

12.1.3.4 if the *IESO* is suspending or resuming operation of all or part of the *IESO-administered markets;*

12.1.3A The *IESO* may *publish* advisory notices in addition to those in 12.1.3, in accordance with the applicable *market manual*, for any additional reason identified by the *IESO* in which the *IESO* believes that the *publication* of an advisory notice would be in the interest of the *IESO-administered markets, market participants,* or the *IESO-controlled grid.*

12.1.4 Where applicable, the corresponding information related to the advisory notices in section 12.1.3 shall be included by the *IESO* in a subsequent *publication* of a scheduled report under section 12.1.1.

12.1.5 The reports referred to in section 12.1.1 and 12.1.3 shall be prepared by the *IESO* in such form and shall contain such information as may be specified in the applicable *market manual*.

12.2 Over-Generation and Under-Generation Advisories

12.2.1 If the *IESO* issues an over-generation advisory notice pursuant to section 12.1.3, the *IESO* shall, unless the *IESO* determines that it is not able to do so for operational or system *security* reasons, and notwithstanding any notification requirements or other conditions specified elsewhere in these *market rules*:

12.2.1.1 solicit and accept additional or revised *bids* from *dispatchable loads* or *electricity storage facilities* willing to increase demand in response to low prices;

12.2.1.2 allow *generators* or *electricity storage facilities* to de-synchronize from the *IESO-controlled grid* or the embedding *facility*, as the case may be, without penalty, some or all of the *generation units* or *electricity storage units* within any *registered facility* in locations designated by the *IESO;* and/or

12.2.1.3 solicit and accept revised *offers* from *generators, electricity storage participants* or *wholesale sellers* that will decrease generation resources in response to low prices, in locations designated by the *IESO*.

12.2.2 If the *IESO* issues an under-generation advisory notice pursuant to section 12.1.3, the *IESO* shall, unless the *IESO* determines that it is not able to do so for operational or system security reasons, and notwithstanding any notification requirements or other conditions specified elsewhere in these *market rules*:

12.2.2.1 solicit and accept additional or revised *bids* from *dispatchable loads* and *electricity storage facilities* that will reduce load in response to higher prices;

12.2.2.2 allow *generators* or *electricity storage facilities* to synchronize to the *IESO-controlled grid* or the embedding *facility*, as the case may be, without penalty, some or all of the *generation units* or *electricity storage units* within any *registered facility* in locations designated by the *IESO*; and/or

12.2.2.3 solicit and accept additional or revised *offers* from *generators, electricity storage participants* or *wholesale sellers* that will

increase generation resources or injections of *energy* in response to higher prices, in locations designated by the *IESO*.

12.2.3 If the *IESO* issues an *operating reserve* shortfall advisory notice pursuant to section 12.1.3, the *IESO* shall, within the period specified in the advisory notice, accept additional or revised *offers* for *operating reserve*.

13. Suspension of Market Operations

13.1 Introduction

13.1.1 The *IESO* may, or may be required to, suspend the operation of all or part of the *IESO-administered markets* in accordance with this section 13. For purposes of this section 13, unless otherwise noted the term "*market operations*" shall mean the operation of all or part of the *IESO-administered markets*.

13.1.2 This section 13 sets forth the procedures the *IESO* must follow in:

13.1.2.1 determining whether to declare a suspension of *market operations;*

13.1.2.2 directing the operation of the *IESO-controlled grid* during suspension of *market operations*; and

13.1.2.3 restoring *market operations* once the conditions triggering suspension are eliminated.

13.1.3 This section 13 also sets forth the requirements that *market participants* must meet immediately prior to, during, and immediately after a suspension of *market operations*.

13.2 Market Suspension Events

13.2.1 Subject to section 13.3, the *IESO* may suspend *market operations* if it determines that any of the conditions described in section 13.2.4 exists or is imminent.

13.2.2 As soon as practical the *IESO* shall notify the *IESO Board,* the *OEB* and relevant government authorities of any suspension of *market operations* pursuant to this section 13.

13.2.3 Upon being notified under section 13.2.2, the *IESO Board* may determine whether to continue the suspension or to resume normal *market operations* under such conditions as the *IESO Board* may specify.

13.2.4 The *IESO* may suspend *market operations* in the event of:

13.2.4.1 *market operations* cannot be continued in a normal manner due to a failure in the software, hardware or communication systems that support *market operations*;

13.2.4.2 a major blackout;

13.2.4.2A the *IESO-controlled grid* breaks up into two or more electrical islands;

13.2.4.3 an *emergency* situation requiring the *IESO* to evacuate its principal control centre and move to a backup control centre, under conditions and subject to the requirements of Chapter 5; or

13.2.4.4 a declaration of an emergency by the Premier of Ontario or a direction from the *Minister* to the *IESO* or to a *market participant* to implement an *emergency* preparedness *plan*.

13.3 Insufficient Reasons for Market Suspension

13.3.1 Notwithstanding section 13.2.4, the *IESO* may suspend *market operations* in response to an event described in that section only if the *IESO* determines that its ability to operate the *IESO-administered markets* in accordance with these *market rules* has become substantially impaired.

13.3.2 The *IESO* shall not suspend *market operations* solely because:

13.3.2.1 the *market price* has reached positive or negative *MMCP*; or

13.3.2.2 some load has been *curtailed*.

13.4 IESO Declaration of Market Suspension

13.4.1 Only a declaration by the *IESO* may suspend *market operations*. If the *IESO* declares a suspension of *market operations*, the *IESO* shall:

13.4.1.1 immediately notify *market participants*; and

13.4.1.2 issue to *market participants* a market suspension notice via such means as the *IESO* determines will ensure timely notification, informing *market participants* of the nature and scope of the suspension and its expected duration, if known.

13.4.2 Any suspension of *market operations* shall commence at the start of the next *dispatch* after the *IESO* makes the declaration, unless the *IESO* suspends *market operations* to protect or restore *reliability*, in which case the suspension shall commence at the time the *IESO* makes the declaration.

13.4.3 The *IESO* may not declare a retroactive suspension of *market operations*.

13.5 IESO Responsibilities During Market Suspension

13.5.1 While a suspension of *market operations* is in effect, the *IESO* shall:

13.5.1.1 prescribe and apply procedures for restoring and maintaining *reliable* operation of the *electricity system* and restoring *market operations* as rapidly as practical, consistent with the safety of persons and *facilities*;

13.5.1.2 endeavour to continue use of normal market information, scheduling and pricing procedures to the extent practical;

13.5.1.3 prescribe and apply *administrative prices* in accordance with section 8.4A.8;

13.5.1.4 [Intentionally left blank]

13.5.1.5 provide timely information to *market participants* concerning the reasons for the suspension and efforts by the *IESO* to resume normal *market operations*; and

13.5.1.6 issue directions, through market suspension advisory notices to *market participants*, that will enable the *IESO* to continue *reliable* operations, continue non-suspended *market operations* and resume normal *market operations* as soon as practical.

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13.6 Participant Responsibilities and Compensation

13.6.1 If the *IESO* suspends market operations, each *market participant* shall:

13.6.1.1 comply with the *IESO's* market suspension advisory notices and any other directions issued by the *IESO*;

13.6.1.2 conduct their operations and interactions with the *IESO* in a manner consistent with such advisory notices and directions; and

13.6.1.3 upon resumption of normal *market operations*, resume normal operations and interactions with the *IESO* pursuant to these *market rules*.

13.6.2 The *IESO* may issue *dispatch instructions* while a suspension of *market operations* is in effect and shall compensate *market participants* for following these *dispatch instructions* based on *administrative prices* established in accordance with section 8.4A.8 rather than on market-determined prices.

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13.7 Ending and Reporting on Market Suspension

13.7.1 The *IESO* shall monitor the conditions which triggered the suspension of *market operations* and, subject to any decision or direction that the *IESO Board* may have given pursuant to section 13.2.3, shall issue a market advisory notice declaring the end of the suspension:

13.7.1.1 as soon as the *IESO* determines that normal *market operations* are possible and will maintain *reliable* system operations; and

13.7.1.2 indicating the *dispatch hour* for which normal *market operations* are to resume, providing at least one hour advance notice.

The *IESO* may, if circumstances warrant and in order to resume normal *market operations* as soon as possible, issue a market advisory declaring the end of the suspension prior to issuing the notice specified in section 13.2.2.

13.7.2 The *IESO* shall, immediately following the end of the suspension of *market operations*, begin a review of events leading to and occurring during the suspension. The *IESO* may require *market participants* to submit information regarding their operations immediately prior to and during the suspension and to assist the *IESO* in analysing the suspension.

13.7.3 Within 10 *business days* following the resumption of normal *market operations*, the *IESO Board* shall provide to all *market participants,* the *OEB* and relevant government authorities a preliminary report describing:

13.7.3.1 the circumstances that triggered suspension of *market operations*;

13.7.3.2 the steps taken by the *IESO* during the period of suspension to ensure *reliable* operations and remedy the causes of the suspension;

13.7.3.3 the actions of *market participants* during the suspension; and

13.7.3.4 any conclusions or recommendations for avoiding similar suspensions in the future.

13.7.4 The *IESO Board* shall provide a final report containing information in the nature of that described in section 13.7.3 to *market participants* and the public as soon as it is practicable to do so.

13.7.5 If the *IESO Board* determines that one or more corrective measures by *market participants* are warranted to avoid the recurrence of a suspension of *market operations*, the *IESO* may direct the affected *market participants* to implement the corrective measures and the affected *market participants* shall implement the corrective measures as soon as practicable.

13.7.6 A *market participant* directed by the *IESO* to implement corrective measures under section 13.7.5 may apply for compensation from the *IESO* where compliance with the *IESO's* direction results in costs or damages to the *market participant*.

13.7.7 Any disputes regarding the compensation referred to in section 13.7.6 shall be resolved using the dispute resolution process set forth in section 2 of Chapter 3.

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18. Capacity Auctions

18.1 Purpose of Capacity Auctions

18.1.1 The *capacity auctions* will acquire *auction capacity* through a competitive auction.

18.1.2 The *IESO* shall specify and *publish* a target capacity amount to be acquired in each *capacity auction*, as specified in the applicable *market manual.*

18.1A Capacity Auction – Transitional Market Rules

18.1A.1 For the purposes of participation in a *capacity auction, market rules* and *market manuals* that specifically concern *capacity auction* participation, the satisfaction of *capacity obligations,* or the performance of requirements directly related to that participation, shall remain in effect from the date of the *capacity auction* until the end of its associated *commitment period,* except as otherwise provided in sections 18.1A.1.1 and 18.1A.3.

18.1A.1.1 Nothing in this section 18.1A shall limit the effectiveness of a *market rule* amendment or *market manual* amendment that expressively excludes the application of sections 18.1A.1 and 18.1A.2.

18.1A.2 Except as otherwise provide in sections 18.1A.1.1 and 18.1A.3, changes to the *market rules* and applicable *market manuals* that specifically concern *capacity auction* participation, the satisfaction of *capacity obligations*, or the performance of requirements directly related to that participation, and which are brought into effect between the date of a given *capacity auction* and the end of its associated *commitment period*, shall be applicable to subsequent *capacity auctions* and their associated *commitment periods.*

18.1A.3 Nothing in this section 18.1A shall limit the effectiveness of an *urgent rule amendment.*

18.1A.4 The *IESO* shall maintain a *published* archive of *market rules* and applicable *market manuals* in effect on the date of a *capacity auction* for a period of 2 years following the end of its associated *commitment period.*

18.2 Participation in Capacity Auctions

18.2.1 No person may participate in a *capacity auction* nor receive a *capacity obligation* unless that person has:

18.2.1.1 been authorized by the *IESO* as a *capacity auction participant* in accordance with section 3 of Chapter 2 and in accordance with the applicable *market manual*;

18.2.1.2 submitted to the *IESO* a *capacity qualification request*, using forms and procedures as may be established by the *IESO* in the applicable *market manual*; and

18.2.1.3 no less than five *business days* prior to the date on which a *capacity auction* is to be conducted, provided to the *IESO* a *capacity auction deposit,* in one or both of the forms set forth in section 18.4.

18.2.2 The following provisions of the *market rules* shall not apply to a *capacity auction participant* that is authorized by the *IESO* to participate only in a *capacity auction* with an *hourly demand response resource*:

18.2.2.1 Chapters 4, 5, and 6;

18.2.2.2 Chapter 7 other than this section 18; and

18.2.2.3 Chapters 8 and 10.

18.2.3 A *capacity auction participant* who obtains a *capacity obligation* shall apply to become authorized by the *IESO* as a *capacity market participant* in accordance with section 3 of Chapter 2.

18.2A Capacity Auction - Capacity Qualification

18.2A.1 For each *obligation period* in a *capacity auction*, the *IESO* shall determine the *unforced capacity* of each *capacity auction resource* where:

18.2A.1.1 the *unforced capacity* of a *capacity auction eligible generation resource*, a *capacity auction eligible storage resource*, or a *capacity dispatchable load resource* is calculated as:

UCAP = ICAP × availability de-rating factor x *performance adjustment factor*

18.2A.1.2 the *unforced capacity* of a *system-backed capacity auction eligible import resource* is calculated as:

UCAP = ICAP x *performance adjustment factor*

18.2A.1.3 the *unforced capacity* of a *generator-backed import resource* is calculated as:

UCAP = (exU*CAP* + esfICAP × *availability de-rating factor)* x *performance adjustment factor*

Where:

(a) 'exU*CAP'* is the total equivalent capacity (in MW) for all *generator-backed import contributors* that are *generation facilities*, as determined by the applicable *control area operator* and provided to the *IESO* in accordance with the applicable *market manual;*

(b) 'esfICAP' is the total *ICAP* (in MW) of all *generator-backed import contributors* that are *electricity storage facilities,* as provided to the *IESO* in accordance with the applicable *market manual.*

18.2A.1.4 the *unforced capacity* of an *hourly demand response resource* is calculated as:

UCAP = ICAP x *performance adjustment factor*

18.2A.2 No *capacity auction resource* may participate in a *capacity auction*, nor receive a *capacity obligation*, in respect of any *obligation period* in relation to which the *capacity auction resource* has an *unforced capacity* of less than one MW.

18.2A.3 The *IESO s*hall notify each *capacity auction participant* of the *unforced capacity* for each of the *capacity auction participant's capacity auction resources* on the date specified in accordance with section 18.5.4.1A.

18.3 Calculation of Capacity Auction Deposits

18.3.1 Following the determination of *unforced capacity* in accordance with section 18.2A, the *IESO* shall determine for each *capacity auction participant*, a *capacity auction deposit* for a *capacity auction* as specified in the applicable *market manual*.

18.3.2 The *IESO* shall review the *capacity auction deposit* and *capacity auction prudential support* of a *capacity transferee* upon receipt of a request for a *capacity obligation* transfer in accordance with section 18.9.1. As a result of a transfer request, the *IESO* may increase the *capacity auction deposit* or *capacity auction prudential support* of a *capacity transferee* and the *IESO* shall notify the *capacity transferee* of any such increase.

18.3.3 Where the amount of a *capacity auction deposit* provided by a *capacity auction participant* exceeds the amount required by the *IESO*, the *IESO* shall return the excess amount to the *capacity auction participant* within five *business days* of such a request from the *capacity auction participant*. Otherwise, that amount shall be held by the *IESO* and shall form part of that *capacity auction participant's capacity auction deposit* for its participation in a subsequent *capacity auction*.

18.4 Capacity Auction Deposits

18.4.1 A *capacity auction deposit* shall be in one or both of the following forms:

18.4.1.1 an irrevocable commercial letter of credit provided by a bank named in a Schedule to the *Bank Act*, (Canada), S.C. 1991, c. 46; or

18.4.1.2 a cash deposit made with the *IESO* by or on behalf of the *capacity auction participant.*

18.4.2 Where all or part of a *capacity auction deposit* is in the form of a standby letter of credit, the following provisions shall apply:

18.4.2.1 the letter of credit shall provide that it is issued subject to either The Uniform Customs and Practice for Documentary Credits, 1993 Revision, ICE Publication No. 500 or The International Standby Practices 1998;

18.4.2.2 the *IESO* shall be named as beneficiary in the letter of credit, the letter of credit shall be irrevocable and partial draws on the letter of credit shall not be prohibited;

18.4.2.3 the only condition on the ability of the *IESO* to draw on the letter of credit shall be the delivery of a certificate by an officer of the *IESO* that a specified amount is owing by the *capacity auction participant* to the *IESO* and that, in accordance with the provisions of the *market rules*, the *IESO* is entitled to payment of that specified amount as of the date of delivery of the certificate;

18.4.2.4 the letter of credit shall either provide for automatic renewal (unless the issuing bank advises the *IESO* at least thirty days prior to the renewal date that the letter of credit will not be renewed) or be for a term of at least one (1) year. Where the *IESO* is advised that a letter of credit is not to be renewed or the term of the letter of credit is to expire, the *capacity auction participant* shall arrange for and deliver additional *capacity auction deposits* if the *capacity auction participant* intends to continue to participate in a *capacity auction*. If such additional *capacity auction deposits* are not received by the *IESO* ten (10) *business days* before the expiry of a letter of credit, the *IESO* shall be entitled as of that time to payment of the full face amount of the letter of credit which amount, once drawn by the *IESO*, shall be treated as a *capacity auction deposit* in the form of cash; and

18.4.2.5 by including a letter of credit as part of a *capacity auction deposit*, the *capacity auction participant* represents and warrants to the *IESO* that the issuance of the letter of credit is not prohibited in any other agreement, including without limitation, a negative pledge given by or in respect of the *capacity auction participant*.

18.4.3 Notwithstanding any other provision of these *market rules*, a person that applies for authorization to participate in the *capacity auction* and that has not applied for authorization to participate, or is not participating, in any other *IESO-administered market* shall not be required to comply with any requirements for authorization other than those set forth in sections 18.2.1.1 to 18.2.1.3.

18.4.4 In the event a *capacity auction participant* has not satisfied the applicable eligibility requirements specified in sections 19.2, 19.3, 19.6, 19.8, 19.9A, or 19.10 of Chapter 7 prior to the start of the applicable *obligation period* and has not elected to buy-out the *capacity obligation* in accordance with section 4.7J.3 of Chapter 9, the *IESO* shall revoke the *capacity obligation* and the *capacity auction participant* shall, at the *IESO's* sole discretion, forfeit its *capacity auction deposit.*

18.5 Capacity Auction Parameters

18.5.1 The *IESO* shall conduct *capacity auctions* at least on an annual basis to acquire *capacity* for a future one-year *commitment period*. In each *capacity auction* the *IESO* shall acquire *auction capacity* for each *obligation period* as specified in the applicable *market manual*.

Demand Curve, Zonal Constraints and Pre-Auction Reports

18.5.2 The *IESO* shall, in accordance with the applicable *market manual*, *publish* a pre-auction report in advance of each *capacity auction*, including the following *capacity auction* demand curve reference points:

18.5.2.1 a *target capacity* in accordance with section 18.1.2;

18.5.2.2 a *capacity auction reference price*;

18.5.2.3 a maximum and minimum *capacity auction clearing price*;

18.5.2.4 [Intentionally left blank – section deleted]

18.5.2.5 a maximum *auction capacity* limit at the maximum *capacity auction clearing price* that a *capacity auction* shall clear; and

18.5.2.6 a maximum *auction capacity* limit that a *capacity auction* shall clear.

18.5.3 The *IESO* shall define *capacity auction zonal constraints* for each *capacity auction* and the *IESO* shall *publish*, in the pre-auction report, those requirements as specified in the applicable *market manual*.

18.5.4 The *IESO* shall specify and *publish* in the pre-auction report the following timelines associated with a *capacity auction*:

18.5.4.1 the deadline to submit a *capacity qualification request* pursuant to section 18.2.1.2;

18.5.4.1A the date on which the *IESO* shall notify *capacity auction participants* of the *unforced capacity* for each *capacity auction resource*;

18.5.4.2 the deadline for a *capacity auction participant* to submit a *capacity auction deposit* in accordance with section 18.2.1.3;

18.5.4.3 the dates on which a *capacity auction participant* may submit *capacity auction offers* for a *capacity auction*;

18.5.4.4 the period over which the *IESO* shall conduct the *capacity auction*; and

18.5.4.5 the date of *capacity auction* post-auction reporting in accordance with sections 18.8.1 and 18.8.2.

18.5.5 The *IESO* shall define the total *auction capacity* that may be provided by all *system-backed capacity import resources* and *generator-backed capacity import resources* in a *capacity auction* for each *obligation period.* The *IESO* shall *publish*, in the pre-auction report, these requirements as specified in the applicable *market manual*.

18.5.6 The *IESO* shall define the total *auction capacity* that may be provided by all *system-backed capacity import resources* and *generator-backed capacity import resources* on each applicable *intertie* in a *capacity auction* for each *obligation period.* The *IESO* shall *publish*, in the pre-auction report, these requirements as specified in the applicable *market manual.*

18.6 Capacity Auction Offers

18.6.1 A capacity auction offer:

18.6.1.1 may be submitted or revised by the *capacity auction participant* on the dates specified in accordance with section 18.5.4 and the applicable *market manual*;

18.6.1.2 shall only be applicable to the *obligation periods* for which a *capacity auction participant* has submitted a *capacity auction offer*, in accordance with the applicable *market manual*; and

18.6.1.3 shall be time stamped by the *IESO* when received.

18.6.2 A *capacity auction offer* shall only be submitted in respect of a given *capacity auction* if:

18.6.2.1 the *capacity auction participant* complies with the *capacity auction participant* requirements in section 18.2.1; and

18.6.2.2 the *capacity auction participant* has not been disqualified from full or partial participation in the *capacity auction* pursuant to sections 19.4.8, 19.5.4, 19.7.4, 19.9.4 or 19.11.4.

18.6.3 A *capacity auction offer* may include up to twenty *price-quantity* pairs for each *obligation period* and shall comply with the following:

18.6.3.1 the *capacity auction offer* shall be for and applicable over an entire *obligation period* associated with a *capacity auction*;

18.6.3.2 the capacity auction offer price in any price-quantity pair shall:

- be expressed in dollars and whole cents per MW-day of *auction capacity* to be provided in each hour of the *availability window* throughout the *obligation period* associated with that *capacity auction*;
- be greater than or equal to $0.00/MW-day;
- not exceed the applicable maximum *capacity auction clearing price;* and
- increase as the associated *capacity auction offer* quantity increases.

18.6.3.3 the *capacity auction offer* quantity in any *price-quantity pair* shall be expressed in MW to not more than one decimal place and the total offered quantity shall not exceed the *unforced capacity* of the *capacity auction resource*; and

18.6.3.4 the *capacity auction offer* shall indicate whether the *capacity auction participant* is willing to clear a *capacity auction* with the full amount of *auction capacity* offered in a lamination or a partial amount of the *auction capacity* offered in a lamination, in accordance with the applicable *market manual*.

18.7 Capacity Auction Clearing Prices and Quantities

18.7.1 The *IESO* shall determine a *capacity auction* demand curve to be utilized for each *obligation period* based upon the *capacity auction* parameters detailed in the pre-auction report pursuant to section 18.5 and in accordance with the applicable *market manual*.

18.7.2 The *IESO* shall, in each *capacity auction*, determine for each *obligation period* the *capacity auction clearing price* in accordance with the applicable *market manual*.

18.7.3 The *IESO* shall, in each *capacity auction*, determine for each *obligation period* the *capacity obligation* for each *capacity auction participant's capacity auction resource(s)* in accordance with section 18.7.5 and the applicable *market manual*.

18.7.4 The IESO shall, for each *capacity auction*, determine for each *obligation period* associated with the *capacity auction*:

18.7.4.1 the *capacity auction clearing prices* for each electrical zone identified in the pre-auction report; and

18.7.4.2 the zonal capacity obligation for each capacity auction participant's capacity auction resource(s),

18.7.5 If two or more *capacity auction participants* submit a *capacity auction offer* at the same price, for the last available quantity, the *capacity auction offer* with the earlier time stamp shall be selected as the successful *capacity auction offer*, in accordance with the applicable *market manual.*

18.8 Post-Auction Notification and Publication

18.8.1 The *IESO* shall, as soon as practicable following the conclusion of a *capacity auction*, *publish* the following in accordance with the applicable *market manual*:

18.8.1.1 the capacity auction clearing price;

18.8.1.2 the amount of *auction capacity* that has been acquired in each electrical zone; and,

18.8.1.3 those capacity auction participants who received a capacity obligation and all respective capacity obligations.

18.8.1.4 [Intentionally left blank – section deleted]

18.8.2 The *IESO* shall, following the conclusion of a *capacity auction*, issue post-auction reports to each *capacity auction participant* by the date specified in accordance with section 18.5.4.5, to detail the *capacity auction offers* that have cleared in the *capacity auction* and the associated *capacity obligations* and *cleared ICAPs* for each *obligation period* in accordance with the applicable *market manual*:

18.8.2.1 the *cleared ICAP* is calculated as:

$$cleared\ ICAP = cleared\ UCAP \times \left(\frac{1}{availability\ de{-}rating\ factor}\right)$$

18.9 Capacity Obligation Transfers

18.9.1 A *capacity transferor* may, subject to *IESO* approval and in accordance with the applicable *market manual*, request a transfer of all or a portion of its *capacity obligation* to a *capacity transferee* provided that the following criteria are met:

18.9.1.1 the quantity to be transferred does not exceed the difference between the *capacity transferee's unforced capacity* of a *capacity auction resource* for the applicable *obligation period,* and its existing

capacity obligation of such *capacity auction resource* for the applicable *obligation period*;

18.9.1.1.1 [Intentionally left blank – section deleted]

18.9.1.2 the *capacity transferor* provides written confirmation to the *IESO* from the *capacity transferee* of its willingness to accept the transfer of a *capacity obligation* from the *capacity transferor*;

18.9.1.3 the *capacity obligation* transfer shall consist of the same attributes (e.g. physical or virtual), as detailed in the applicable *market manual,* as the *capacity transferor's capacity obligation*;

18.9.1.4 the quantity to be transferred is in increments of 0.1MW, and the resulting *capacity obligations* for both the *capacity transferor* and *capacity transferee* following the transfer shall be 0 MW, or greater than or equal to one MW; and

18.9.1.5 [Intentionally left blank – section deleted]

18.9.1.6 [Intentionally left blank – section deleted]

18.9.1.7 [Intentionally left blank – section deleted]

18.9.1.8 *capacity obligation* transfers must not result in the violation of any constraint as defined in the pre-auction report

18.9.1A Where the *capacity obligation* is transferred between electrical zones, the *capacity transferee* shall be settled based upon the *capacity auction clearing price* received by the *capacity transferor* when the *capacity obligation* first cleared the *capacity auction* in accordance with the applicable *market manual*.

18.9.2 For each transfer request that satisfies the criteria in section 18.9.1, the *IESO* shall determine the *capacity transferee's* revised *capacity auction deposit* and/or *capacity prudential support obligation*, as applicable, in accordance with section 18.3.2 and section 5B.3.3 of Chapter 2.

18.9.3 The *capacity transferee* shall provide the *IESO*, within five *business days* of receiving notification from the *IESO* or within such a longer period of time as may be agreed between the *IESO* and the *capacity transferee*, any additional *capacity auction deposit* and/or *capacity prudential support obligation* that may be required as a result of a transfer request.

18.9.4 After the revised *capacity auction deposits* and/or *capacity prudential support obligations* have been satisfied by the *capacity transferee*, the *IESO* shall notify the *capacity transferor* and *capacity transferee* of its approval or rejection, and the *IESO* shall *publish* updated post-auction reports pursuant to section 18.8. If the *IESO* approves the transfer, the *capacity transferor* may request a reassessment of its *capacity auction deposits* and/or *capacity prudential support obligation* to reflect its revised *capacity obligation* and the *IESO* shall remit any excess *capacity auction deposits* and/or *capacity prudential support obligation*.

19. Capacity Market Participants with Capacity Obligations

19.1 Purpose

19.1.1 This section details how a *capacity market participant* must satisfy a *capacity* obligation with a *capacity auction resource*.

19.1.2 Capacity auction resources eligible to satisfy a capacity obligation are:

19.1.2.1 an hourly demand response resource;

19.1.2.2 a capacity dispatchable load resource;

19.1.2.3 a capacity generation resource;

19.1.2.4 a system-backed capacity import resource;

19.1.2.5 a capacity storage resource; or

19.1.2.6 a generator-backed capacity import resource.

19.1.3 [Intentionally left blank – section deleted]

19.2 Eligibility Requirements for Hourly Demand Response Resources

19.2.1 A *capacity market participant* is eligible to satisfy its *capacity obligation* with an *hourly demand response resource* provided that the *capacity market participant*:

19.2.1.1 demonstrates to the satisfaction of the *IESO* that it can provide the *capacity obligation*, as specified in the applicable *market manual*;

19.2.1.2 registers its *facilities* and *demand response contributors* as applicable, to the satisfaction of the *IESO*, in accordance with the applicable *market manual*. The *capacity market participant* shall not modify, vary or amend in any material respect any of the features or specifications of any *facility* without first requesting *IESO* authorization and approval in accordance with the applicable *market manual*;

19.2.1.3 [Intentionally left blank – section deleted]

19.2.1.4 has provided *prudential support* and *capacity prudential support* in accordance with section 5 of Chapter 2.

19.2.2 The *IESO* may refuse the participation of an *hourly demand response resource* in a future *capacity auction* if the resource's participation would negatively impact the *reliable* operation of the *IESO-controlled grid*.

19.2.3 The *IESO* may remove or temporarily remove a *capacity market participant's hourly demand response resource* from its participation as a *capacity market participant* if the resource's continued participation would negatively impact the *reliable* operation of the *IESO-controlled grid.* A *capacity market participant* that is removed pursuant to this section 19.2.3 shall not receive an availability payment in accordance with section 19.4.1 for the duration of the removal.

19.2.4 The following provisions of the *market rules* shall not apply to a *capacity market participant* that is authorized by the *IESO* to participate only with an *hourly demand response resource* and is not a *wholesale consumer* that is a *non-dispatchable load*:

19.2.4.1 Chapter 2, sections 5A and 8;

19.2.4.2 Chapter 5, other than section 1.2.1 to 1.2.3, 2.3, 2.4, 5.8 and 5.9;

19.2.4.3 Chapter 7 section 7; and

19.2.4.4 Chapters 6, 8, 10.

19.2.5 A *wholesale consumer* that is a *non-dispatchable load* may participate as a *demand response contributor* to an *hourly demand response resource* to satisfy a *capacity obligation*, provided that the *non-dispatchable load* meets all the applicable eligibility requirements of this section 19.2, and the requirements in the *market rules* that are applicable to a *wholesale consumer* that is a *non-dispatchable load*.

19.3 Eligibility Requirements for Capacity Dispatchable Load Resources

19.3.1 A *capacity market participant* is eligible to satisfy its *capacity obligation* with a *capacity dispatchable load resource*, provided that the *capacity market participant*:

19.3.1.1 demonstrates to the satisfaction of the *IESO* that it can provide the *capacity obligation*, as specified in the applicable *market manual*;

19.3.1.2 is authorized as a *wholesale consumer;*

19.3.1.3 registers its *facilities* in accordance with the registration requirements for *wholesale consumers* that are *dispatchable loads*. The *capacity market participant* shall not modify, vary or amend in any material respect any of the features or specifications of any resource without first requesting *IESO* authorization and approval in accordance with the applicable *market manual*;

19.3.1.4 satisfies the *connection assessment* requirements in accordance with section 6 of Chapter 4, if required by the *IESO* in accordance with the *applicable market manual*;

19.3.1.5 has provided *prudential support* and *capacity prudential support* in accordance with section 5 of Chapter 2.

19.3.2 [Intentionally left blank – section deleted]

19.3.3 [Intentionally left blank – section deleted]

19.4 Energy Market Participation for Hourly Demand Response Resources

19.4.1 A *capacity market participant* with a *capacity obligation* participating with an *hourly demand response resource* shall receive an availability payment during the *obligation period* in accordance with this section and the applicable *market manual.* Availability payments may be offset by non-performance charges in accordance with section 4.7J of Chapter 9.

Standby and Activation Notices

19.4.2 If an *hourly demand response resource* has a day-ahead *schedule of record* or a *pre-dispatch schedule* less than the resource's total *bid* quantity, or if the

applicable pre-dispatch shadow price for an *hourly demand response resource* is equal to or greater than the standby notice price threshold, determined by the *IESO,* for at least one hour during the *dispatch day availability window*, the *IESO* shall issue a standby notice to the applicable *capacity market participant* by 07:00 EST in accordance with the applicable *market manual*.

19.4.3 If the *IESO* does not issue a standby notice to a *capacity market participant* by 07:00 EST, the *capacity market participant* shall remove their *bids* for the *hourly demand response resource* as soon as practicable and before 9:00 EST. A capacity *market participant* that does not remove their *bids* for the *hourly demand response resource* before 9:00 EST shall comply with any corresponding activation notices issued by the *IESO* in accordance with section 19.4.5.

19.4.4 The *IESO* shall issue an activation notice to a *capacity market participant* ahead of the activation period, in accordance with the applicable *market manual* if a standby notice has been issued in accordance with section 19.4.2 or a *capacity market participant* has not removed their *bids* in accordance with section 19.4.3, and the applicable *hourly demand response resource* has a *pre-dispatch schedule* less than the resource's total *bid* quantity for at least one hour during the *dispatch day availability window*.

19.4.5 If a *capacity market participant* receives an activation notice pursuant to section 19.4.4, the *capacity market participant* shall comply with the activation notice, unless such a reduction would endanger the safety of any person, damage equipment, or violate any *applicable law*. In such circumstances, the *capacity market participant* shall notify the *IESO* as soon as practicable.

19.4.6 A *capacity market participant* may be subject to non-performance charges, and the *IESO* may take action pursuant to sections 19.2.2 and 19.2.3 if a *capacity market participant* does not comply with an activation notice pursuant to this section 19, in accordance with the applicable *market manual*. The *capacity market participant* may also be subject to compliance actions in accordance with section 6 of Chapter 3.

19.4.7 A *capacity market participant* that expects its *hourly demand response resource* to operate in a manner that differs from the activation notice issued to it in accordance with this section 19 shall notify the *IESO* as soon as possible and in accordance with the applicable *market manual*.

19.4.8 The *IESO* may disqualify from future participation in the *capacity auction* any *capacity market participant* that fails to reduce its consumption in order to satisfy its *capacity obligation* when called upon in accordance with this section 19.

Non-performance Events for Hourly Demand Response Resources

19.4.9 In the event of a reduction in the *demand response capacity* of an *hourly demand response resource*, associated with a *capacity obligation* acquired through a *capacity auction*, the *capacity market participant* shall notify the *IESO* as per the procedures and criteria specified in the applicable *market manual*.

19.4.9A [Intentionally left blank – section deleted]

19.4.10 A *capacity market participant* shall reduce its *bid* to take into account and reflect the maximum *demand response capacity* that it reasonably expects it can provide in accordance with section 3.5.6 and due to any non-performance event related to an *hourly demand response resource* in an *obligation period*.

19.4.10A Where a *contributor outage* has occurred and such *contributor outage*:

(a) began not more than 14 days prior to the day on which there is an activation; and

(b) ends within one hour prior to such activation or within the *activation window* of such activation;

then the *capacity market participant* may *notify* the *IESO* within five *business days* of the activation notice, in accordance with the process and requirements described in the applicable *market manual*.

19.4.10B Where the *IESO* receives a valid *contributor outage* notice pursuant to section 19.4.10A, the *IESO* shall adjust the assessment of the *capacity market participant's* performance as set out in the applicable *market manual.*

Capacity Auction Testing for Hourly Demand Response Resources

19.4.11 The *IESO* may, in accordance with the applicable *market manual*, direct a *capacity market participant* with a *capacity obligation* to perform a *capacity auction dispatch test* for each *hourly demand response resource* up to a maximum of two *capacity auction dispatch tests* per *obligation period.*

19.4.11A The *capacity market participant* shall perform a *capacity auction capacity test* once per *obligation period* for each *hourly demand response resource*, in accordance with the applicable *market manual*. The *capacity auction capacity test* shall occur within a five *business day* testing window determined by the *IESO*. The *IESO* shall provide notification to a *capacity market participant* of the *capacity auction capacity test* no less than ten *business days* prior to the first day of the testing window.

19.4.12 If a *capacity market participant* fails during a *capacity auction dispatch test* or a *capacity auction capacity test* performed pursuant to section 19.4.11 or 19.4.11A, respectively, the *capacity market participant* shall be subject to non-performance charges in accordance with the applicable *market manual* and Chapter 9. Failure during a *capacity auction dispatch test* or a *capacity auction capacity test* shall be considered a breach of the *market rules* and may result in sanctions in accordance with section 6.2 of Chapter 3.

19.4.13 The *IESO* shall provide a *capacity market participant* day-ahead notification of a *capacity auction dispatch test* pursuant to section 19.4.11 and the test activation shall occur within the *availability window* of an *obligation period*.

19.4.14 The *capacity auction dispatch test* shall occur in accordance with the *hourly demand response resource* activation process specified in this section 19.4.

19.4.15 The *hourly demand response resource* shall be entitled to compensation for valid *capacity auction dispatch tests* conducted during a *commitment period* pursuant to this section 19.4 and in accordance with the applicable *market manuals*. The *hourly demand response resource* shall not be entitled to compensation for any costs related to any *capacity auction capacity test*.

19.4.16 The *capacity market participant* shall submit to the *IESO* all of the testing data and other information in accordance with the requirements and deadlines set out in the applicable *market manual*. If the *capacity market participant* fails to submit the entirety of such testing data and other information within such deadlines, the *capacity market participant* is deemed to have delivered zero MWh during the *capacity auction capacity test* or *capacity auction dispatch test*, as the case may be.

19.4.17 The *IESO* shall assess, in accordance with the applicable *market manual,* the testing data and other information submitted by the *capacity market participant* and shall provide notice to the *capacity market participant* of the results of the *capacity auction capacity test.*

19.4.18 Where the notice referred to in section 19.4.17 indicates that the *hourly demand response resource's* average hourly capacity delivered over the four hour testing period was less than 90% of its *cleared UCAP* and such *capacity market participant* has not filed a *notice of disagreement* in regards to the outcomes of the *capacity auction capacity test* in accordance with section 6.8 of chapter 9, such *capacity market participant's capacity obligation* for such *hourly demand response resource* shall, effective as of one *business day* following the time period referred to in section 6.3.14 of chapter 9, be reduced to the amount of capacity that was determined by the *IESO,* in accordance with the applicable *market manual,* to have been provided by the *capacity market participant* during

the *capacity auction capacity test*. If such reduction in the *capacity market participant's capacity obligation* for such *hourly demand response resource* results in such *capacity obligation* being less than one MW, the remainder of the *capacity market participant's capacity obligation* for such *hourly demand response resource* is forfeited effective as of one *business day* following the time period referred to in section 6.3.14 of chapter 9.

19.4.19 Where the notice referred to in section 19.4.17 indicates that the *hourly demand response resource's* average hourly capacity delivered over the four hour testing period was less than 90% of its *cleared UCAP*, such *capacity market participant* shall be subject to an in-period *cleared UCAP* adjustment charge pursuant to section 4.7J.2.9 of Chapter 9.

19.4.20 After the relevant *capacity market participant* has made payment in full of any *settlement amount* owing pursuant to section 4.7J.2.9 of Chapter 9, in respect of the same *capacity auction capacity test* for which its *capacity obligation* is being reduced pursuant to this section 19.4.16, the *capacity market participant* may request a reassessment of its *capacity prudential support obligation* to reflect its revised *capacity obligation* and the *IESO* shall remit any excess prudential support.

Activation of Hourly Demand Response Resources leading up to or during an Emergency Operating State

19.4.21 A *capacity market participant* satisfying a *capacity obligation* using an *hourly demand response resource* shall be entitled to compensation for an activation leading up to or during an *emergency operating state* pursuant to section 2.3 of Chapter 5, and in accordance with the applicable *market manuals*.

19.5 Energy Market Participation for Capacity Dispatchable Load Resources

19.5.1 A *capacity market participant* with a *capacity obligation* participating with a *capacity dispatchable load resource* shall receive an availability payment during the *obligation period*, in accordance with this section and the applicable *market manual*. Availability payments may be offset by non-performance charges in accordance with section 4.7J of Chapter 9.

Dispatch of Capacity Dispatchable Load Resources

19.5.2 The *IESO* shall schedule a *capacity dispatchable load resource* in the *real-time market* and issue a *dispatch instruction* in accordance with Chapter 7.

19.5.3 A *capacity dispatchable load resource* shall comply with *IESO dispatch instructions* in accordance with Chapter 7.

19.5.4 The *IESO* may disqualify from future participation in the *capacity auction* any *capacity market participant* that fails to reduce its consumption in order to satisfy its *capacity obligation* when called upon in accordance with this section 19.

Outage Notification Requirements for Capacity Dispatchable Load Resources

19.5.5 Each *capacity dispatchable load resource* shall comply with the *outage* notification requirements of Chapter 5.

19.5.6 A *capacity dispatchable load resource* shall reduce its *bid* to take into account and reflect the maximum *demand response capacity* that it reasonably expects it can consume in accordance with section 3.5.6.

Capacity Auction Testing for Capacity Dispatchable Load Resources

19.5.7 The *IESO* may, in accordance with the applicable *market manual*, direct a *capacity market participant* to perform a *capacity auction dispatch test* for each resource up to a maximum of two *capacity auction dispatch test* per *obligation period.*

19.5.7A The *capacity market participant* shall perform a *capacity auction capacity test* once per *obligation period* for each *capacity dispatchable load resource*, in accordance with the applicable *market manual*. The *capacity auction capacity test* shall occur within a five *business day* testing window determined by the *IESO*. The *IESO* shall provide notification to a *capacity market participant* of the *capacity auction capacity test* no less than ten *business days* prior to the first day of the testing window.

19.5.8 If a *capacity market participant* fails a *capacity auction dispatch test* or a *capacity auction capacity test* performed pursuant to section 19.5.7 or 19.5.7A, the *capacity market participant* shall be subject to non-performance charges in accordance with the applicable *market manual.* Failure during a *capacity auction dispatch test* or *capacity auction capacity test* shall be considered a breach of the *market rules* and may result in sanctions in accordance with section 6.2 of Chapter 3.

19.5.9 The *IESO* shall provide a *capacity dispatchable load resource* day-ahead notification of a *capacity auction dispatch test* and the test activation shall occur within the *availability window* of an *obligation period*.

19.5.10 The *capacity auction dispatch test* shall occur in accordance with the *dispatch instructions* for a *dispatchable load facility* specified in this section 19.5.

19.5.11 The *capacity dispatchable load resource* shall not be entitled to compensation for any costs related to any valid *capacity auction dispatch test* or *capacity auction capacity test* conducted during an *obligation period* pursuant to this section 19.5.

19.5.12 The *capacity market participant* shall submit to the *IESO* all of the testing data and other information in accordance with the requirements and deadlines set out in the applicable *market manual*. If the *capacity market participant* fails to submit the entirety of such testing data and other information within such deadlines, the *capacity market participant* is deemed to have delivered zero MWh during the *capacity auction capacity test*.

19.5.13 The *IESO* shall assess, in accordance with the applicable *market manual,* the testing data and other information submitted by the *capacity market participant* and shall provide notice to the *capacity market participant* of the results of the *capacity auction capacity test.*

19.6 Eligibility Requirements for Capacity Generation Resources

19.6.1 A *capacity market participant* is eligible to satisfy its *capacity obligation* as a *capacity generation resource*, provided that the *capacity market participant*:

19.6.1.1 demonstrates to the satisfaction of the IESO that it can provide the *capacity obligation*, as specified in the applicable *market manual;*

19.6.1.2 is authorized as a *generator;*

19.6.1.3 registers its *facilities* in accordance with the registration requirements applicable to *generation facilities*. The *capacity market participant* shall not modify, vary or amend in any material respect any of the features or specifications of any *facility* without first requesting *IESO* authorization and approval in accordance with the applicable *market manual;*

19.6.1.4 satisfies the *connection assessment* requirements in accordance with section 6 of Chapter 4, if required by the *IESO* in accordance with the applicable *market manual;*

19.6.1.5 has provided *prudential support* and *capacity prudential support* in accordance with section 5 of Chapter 2.

19.7 Energy Market Participation for Capacity Generation Resources

19.7.1 A *capacity market participant* satisfying its *capacity obligation* with a *capacity generation resource* shall receive an availability payment during the *obligation period*, in accordance with this section and the applicable *market manual*. Availability payments may be offset by non-performance charges in accordance with section 4.7J of Chapter 9.

Dispatch of Resources

19.7.2 The *IESO* shall schedule a *capacity generation resource* in the *energy market,* and issue *dispatch instructions* in accordance with Chapter 7.

19.7.3 A *capacity generation resource* shall comply with *IESO dispatch instructions* in accordance with Chapter 7.

19.7.4 The *IESO* may disqualify from future participation in the *capacity auction* any *capacity market participant* that fails to inject *energy* in order to satisfy its *capacity obligation* when called upon in accordance with this section 19.

Outage Notification Requirements for Capacity Generation Resources

19.7.5 Each *capacity generation resource* shall comply with the *outage* notification requirements of Chapter 5.

19.7.6 A *capacity generation resource* shall reduce its *offer* to reflect the maximum capacity that it reasonably expects it can inject in accordance with section 3.5.6.

Capacity Auction Testing for Capacity Generation Resources

19.7.7 The *IESO* may, in accordance with the applicable *market manual*, direct a *capacity market participant* to perform a *capacity auction dispatch test* for each *capacity generation resource* up to a maximum of two *capacity auction dispatch tests* per *obligation period.*

19.7.7A The *capacity market participant* shall perform a *capacity auction capacity test* once per *obligation period* for each *capacity generation resource*, in accordance with the applicable *market manual*. The *capacity auction capacity test* shall occur within a five *business day* testing window determined by the *IESO*. The *IESO* shall provide notification to a *capacity market participant* of the *capacity auction capacity test* no less than ten *business days* prior to the first day of the testing window.

19.7.8 If a *capacity market participant* fails a *capacity auction dispatch test* or a *capacity auction capacity test* performed pursuant to section 19.7.7 or 19.7.7A, the *capacity market participant* shall be subject to non-performance charges in accordance with the applicable *market manual.* Failure during a *capacity auction dispatch test* or *capacity auction capacity test* shall be considered a breach of the *market rules* and may result in sanctions in accordance with section 6.2 of Chapter 3.

19.7.9 The *IESO* shall provide a *capacity generation resource* that is not a *quick start facility* notification up to one *business day* in advance of the *capacity auction dispatch test* and the *capacity auction dispatch test* shall occur within the *availability window* of an *obligation period*.

19.7.9A The *IESO* shall provide a *capacity generation resource* that is a *quick start facility* notification at least one hour in advance of the dispatch hour of the *capacity auction dispatch test* and the *capacity auction dispatch test* shall occur within the *availability window* of an *obligation period*.

19.7.10 The *capacity auction dispatch test* shall occur in accordance with the *dispatch instructions* specified in this section 19.7

19.7.11 The *capacity market participant* shall submit to the *IESO* all of the testing data and other information in accordance with the requirements and deadlines set out in the applicable *market manual*. If the *capacity market participant* fails to submit the entirety of such testing data and other information within such deadlines the *capacity market participant* is deemed to have delivered zero MWh during the *capacity auction capacity test*.

19.7.12 The *IESO* shall assess, in accordance with the applicable *market manual,* the testing data and other information submitted by the *capacity market participant* and shall provide notice to the *capacity market participant* of the results of the *capacity auction capacity test.*

19.8 Eligibility Requirements for System-Backed Capacity Import Resources

19.8.1 A *capacity market participant* is eligible to satisfy its *capacity obligation* with a *system-backed capacity import resource* provided that the *capacity market participant*:

19.8.1.1 demonstrates to the satisfaction of the *IESO* that it can provide the *capacity obligation*, as specified in the applicable *market manual*;

19.8.1.2 is authorized as a *market participant* eligible to import *energy;*

19.8.1.3 is registered as a *boundary entity* pursuant to section 2.2.7; and

19.8.1.4 has provided *prudential support* and *capacity prudential support* in accordance with section 5 of Chapter 2.

19.9 Energy Market Participation for System-Backed Capacity Import Resources

19.9.1 A *capacity market participant* satisfying its *capacity obligation* with a *system-backed capacity import resource* shall receive an availability payment during the *obligation period*, in accordance with this section and the applicable *market manual*. Availability payments may be offset by non-performance charges in accordance with section 4.7J of Chapter 9.

Dispatch of System-Backed Capacity Import Resources

19.9.2 The *IESO* shall schedule a *system-backed capacity import resource* in the *energy market,* and issue *dispatch instructions* in accordance with Chapter 7.

19.9.3 A *system-backed capacity import resource* shall comply with *IESO dispatch instructions* in accordance with Chapter 7.

19.9.4 The *IESO* may disqualify from future participation in the *capacity auction* any *capacity market participant* that fails to schedule *energy* with the appropriate *scheduling entity* in order to satisfy its *capacity obligation* when called upon in accordance with this section 19.

Outage Notification Requirements for System-Backed Capacity Import Resources

19.9.5 A *system-backed capacity import resource* shall reduce or remove its *offer* to reflect the maximum capacity that it reasonably expects it can provide in accordance with section 3.5.6.

Capacity Auction Testing for System-Backed Capacity Import Resources

19.9.6 The *IESO* may, in accordance with the applicable *market manual*, direct a *capacity market participant* to perform a *capacity auction capacity test* for each *system-backed capacity import resource,* up to a maximum of two *capacity auction capacity tests* per *obligation period,* to verify that the *cleared ICAP* can be satisfied for a duration specified in the applicable *market manual* by the *system-back capacity import resource.*

19.9.7 If a *capacity market participant* fails a *capacity auction capacity test* performed pursuant to section 19.9.6, the *capacity market participant* shall be subject to non-performance charges in accordance with Chapter 9 and the applicable *market manual.* Failure during a *capacity auction capacity test* shall be considered a breach of the *market rules* and may result in sanctions in accordance with section 6.2 of Chapter 3.

19.9.8 The *IESO* shall provide a *system-backed capacity import resource* notification at least two hours in advance of the dispatch hour of the *capacity auction capacity test* and the *capacity auction capacity test* shall occur within the *availability window* of an *obligation period*.

19.9.9 The *capacity auction capacity test* shall occur in accordance with the *dispatch instructions* specified in this section 19.9.

19.9.10 The *IESO* shall assess, in accordance with the applicable *market manual,* the relevant testing and shall provide notice to the *capacity market participant* of the results of the *capacity auction capacity test.*

19.9A Eligibility Requirements for Generator-Backed Capacity Import Resources

19.9A.1 A *capacity market participant* is eligible to satisfy its *capacity obligation* with a *generator-backed capacity import resource* provided that the *capacity market participant*:

19.9A.1.1 demonstrates to the satisfaction of the *IESO* that it can provide the *capacity obligation*, as specified in the applicable *market manual*;

19.9A.1.2 is authorized as a *market participant* eligible to import *energy* in association with a *boundary entity; and*

19.9A.1.3 has provided *prudential support* and *capacity prudential support* in accordance with section 5 of Chapter 2.

19.9B Energy Market Participation for Generator-Backed Capacity Import Resources

19.9B.1 A *capacity market participant* satisfying its *capacity obligation* with a *generator-backed capacity import resource* shall receive an availability payment during the *obligation period*, in accordance with this section and the applicable *market manual*. Availability payments may be offset by non-performance charges in accordance with section 4.7J of Chapter 9.

Dispatch of Generator-Backed Capacity Import Resources

19.9B.2 The *IESO* shall schedule a *generator-backed capacity import resource* in the *energy market,* and issue *dispatch instructions* in accordance with Chapter 7.

19.9B.3 A *generator-backed capacity import resource* shall comply with *IESO dispatch instructions* in accordance with Chapter 7.

19.9B.4 The *IESO* may disqualify from future participation in the *capacity auction* any *capacity market participant* that fails to schedule *energy* with the appropriate scheduling entity in order to satisfy its *capacity obligation* when called upon in accordance with this section 19.

Outage Notification Requirements for Generator-Backed Capacity Import Resources

19.9B.5 A *generator-backed capacity import resource* shall reduce or remove its *offer* to reflect the maximum capacity that it reasonably expects it can provide in accordance with section 3.5.6.

19.9B.6 A *generator-backed capacity import resource* shall comply with the *outage* notification requirements specified in the applicable *market manual.*

Capacity Auction Testing for Generator-Backed Capacity Import Resources

19.9B.7 A *capacity market participant* satisfying its *capacity obligation* with a *generator-backed capacity import resource* must perform a *capacity auction capacity test*, per *obligation period*,, in accordance with the applicable *market manual*, by scheduling an *energy* import into the *IESO-administered market* for at least one hour that coincides with the timing of its scheduled four hour activation in the neighbouring *control area*, on a date that falls within the first two months of the applicable *obligation period* and by submitting data to the *IESO* to confirm the capability of the *generator-backed capacity import resource* to inject at least its *cleared ICAP* into the *control area* in which it is located for four consecutive hours within the *availability window.*

19.9B.8 A *capacity market participant* that fails to submit data pursuant to section 19.9B.7 in the form specified by the *IESO,* in a timely manner shall be subject to a capacity obligation administration charge pursuant to section 4.7J.2.3 of Chapter 9.

19.9B.9 If a *capacity market participant* fails a *capacity auction capacity test* performed pursuant to section 19.9B.7, the *capacity market participant* shall be subject to non-performance charges in accordance with the applicable *market manual.*

Failure during a *capacity auction dispatch test* or a *capacity auction capacity test* shall be considered a breach of the *market rules* and may result in sanctions in accordance with section 6.2 of Chapter 3.

19.9B.10 The *capacity auction capacity test* shall occur in accordance with the *dispatch instructions* specified in this section 19.9B.

19.9B.11 The *capacity market participant* shall submit to the *IESO* all of the testing data and other information in accordance with the requirements and deadlines set out in the applicable *market manual*. If the *capacity market participant* fails to submit the entirety of such testing data and other information within such deadlines the *capacity market participant* is deemed to have delivered zero MWh during the *capacity auction capacity test*.

19.9B.12 The *IESO* shall assess, in accordance with the applicable *market manual,* the testing data and other information submitted by the *capacity market participant* and shall provide notice to the *capacity market participant* of the results of the *capacity auction capacity test.*

19.10 Eligibility Requirements for Capacity Storage Resources

19.10.1 A *capacity market participant* is eligible to satisfy its *capacity obligation* with a *capacity storage resource* provided that the *capacity market participant*:

19.10.1.1 demonstrates to the satisfaction of the *IESO* that it can satisfy the *capacity obligation*, as specified in the applicable *market manual. Capacity storage resources* must satisfy *capacity obligations* with injections of *energy* into the *IESO-controlled grid*;

19.10.1.2 is a registered *market participant* authorized as an *electricity storage participant* in accordance with the applicable *market manual;*

19.10.1.3 registers its *facilities* in accordance with the registration requirements applicable to *electricity storage facilities*. The *capacity market participant* shall not modify, vary or amend in any material respect any of the features or specifications of any *facility* without first requesting *IESO* authorization and approval in accordance with the applicable *market manual;*

19.10.1.4 satisfies the *connection assessment* requirements in accordance with section 6 of Chapter 4, if required by the *IESO* in accordance with the applicable *market manual;*

19.10.1.5 has provided *prudential support* and *capacity prudential support* in accordance with section 5 of Chapter 2.

19.11 Energy Market Participation for Capacity Storage Resources

19.11.1 A *capacity market participant* satisfying its *capacity obligation* with a *capacity storage resource* shall receive an availability payment during the *obligation period*, in accordance with this section and the applicable *market manual*. Availability payments may be offset by non-performance charges in accordance with section 4.7J of Chapter 9.

Dispatch of Capacity Storage Resources

19.11.2 The *IESO* shall schedule a *capacity storage resource* as it would an *electricity storage facility* in the *energy market,* and issue *dispatch instructions* in accordance with Chapter 7.

19.11.3 A *capacity storage resource* shall comply with *IESO dispatch instructions* in accordance with Chapter 7.

19.11.4 The *IESO* may disqualify from future participation in the *capacity auction* any *capacity market participant* that fails to inject *energy* in order to satisfy its *capacity obligation* when called upon in accordance with this section 19.

Outage Notification Requirements for Capacity Storage Resources

19.11.5 Each *capacity storage resource* shall comply with its *outage* notification requirements as outlined in Chapter 5.

19.11.6 A *capacity storage resource* shall reduce its *offer* to reflect the maximum capacity that it reasonably expects it can inject in accordance with section 3.5.6.

Capacity Auction Testing for Capacity Storage Resources

19.11.7 The *IESO* may, in accordance with the applicable *market manual*, direct a *capacity market participant* to perform a *capacity auction dispatch test* for each *capacity storage resource* up to a maximum of two *capacity auction dispatch tests*per *obligation period.*

19.11.7A The *capacity market participant* shall perform a *capacity auction capacity test* once per *obligation period* for each *capacity storage resource*, in accordance with the applicable *market manual*. The *capacity auction capacity test* shall occur within a five *business day* testing window determined by the *IESO*. The *IESO*

shall provide notification to a *capacity market participant* of the *capacity auction capacity test* no less than *ten business* days prior to the first day of the testing window.

19.11.8 If a *capacity market participant* fails a test performed pursuant to section 19.11.7 or 19.11.7A, the *capacity market participant* shall be subject to non-performance charges in accordance with the applicable *market manual.* Failure during a *capacity auction dispatch test* or *capacity auction capacity test* shall be considered a breach of the *market rules* and may result in sanctions in accordance with section 6.2 of Chapter 3.

19.11.9 The *IESO* shall provide a *capacity storage resource* notification at least one hour in advance of the dispatch hour of the *capacity auction dispatch test* and the *capacity auction dispatch test* shall occur within the *availability window* of an *obligation period*.

19.11.10 The *capacity auction capacity test* shall occur in accordance with the *dispatch instructions* specified in this section 19.11.

19.11.11 The *capacity market participant* shall submit to the *IESO* all of the testing data and other information in accordance with the requirements and deadlines set out in the applicable *market manual*. If the *capacity market participant* fails to submit the entirety of such testing data and other information within such deadlines the *capacity market participant* is deemed to have delivered zero MWh during the *capacity auction capacity test*.

19.11.12 The *IESO* shall assess, in accordance with the applicable *market manual,* the testing data and other information submitted by the *capacity market participant* and shall provide notice to the *capacity market participant* of the results of the *capacity auction capacity test.*

20. Capacity Exports in the IESO-Administered Market

20.1 Capacity Export Request and IESO Review

20.1.1 A *market participant* that wishes to export eligible capacity shall submit a *capacity export request* to the *IESO,* in the form, within the timelines and as further prescribed in the applicable *market manual*.

20.1.2 The *IESO* shall approve or deny *capacity export requests* based on the *IESO's*

review, as prescribed in the applicable *market manual.*

20.1.3 The *IESO* may, after approving or partially approving a *capacity export request* and prior to the *market participant* committing capacity to an external *control area*, revoke an approval of a *capacity export request* in order to maintain the *reliability* of the *IESO-controlled grid*, or if the *IESO* becomes aware of any event or change in circumstances that may alter the *IESO's* approval of a *capacity export request*.

20.2 Capacity Export Commitment Process

20.2.1 A *market participant* may only commit capacity to an external *control area* in accordance with the time periods, quantities and other terms and conditions of the *IESO's* approval of the *capacity export request*.

20.2.2 A *market participant* that commits its capacity to an external *control area* shall notify the *IESO* of the commitment and any subsequent changes to the commitment in the time and manner prescribed in the applicable *market manual*.

20.3 Called Capacity Exports

20.3.1 The *IESO* shall only accept and schedule a *called capacity export* in accordance with section 20.4 when advised by the external *control area operator* that the applicable external *control area* is anticipating or experiencing an *adequacy* shortfall, as may be specified in the applicable *capacity export agreement*.

20.3.2 A *market participant* shall notify the *IESO* concerning the details of a *called capacity export* in the time and manner prescribed in the applicable *market manual*.

20.4 Called Capacity Export Scheduling and Dispatch

20.4.1 All export *bids* for *called capacity exports* shall be submitted in the form and within the timelines prescribed in the applicable *market manual*.

20.4.2 Notwithstanding any provision of the *market rules* that may require the *IESO* to restrict exports in order to maintain the *adequacy* of the *IESO-controlled grid*, the *IESO* may schedule and *dispatch called capacity exports* in accordance with applicable *capacity export agreements* (the relevant details of which are specified in the applicable *market manual*).

21. Electricity Storage in the IESO-Administered Market

21.1 Purpose

21.1.1 This section 21 sets out *market rules* intended to facilitate the near-term inclusion of *electricity storage participants* in the *IESO-administered markets* and the connection of *electricity storage facilities* to the *electricity system*. A number of the provisions of this section would, based on their subject matter, ordinarily be included under different chapters or sections of the *market rules*. However, these provisions have been gathered together here under a single section for convenience of reference and until such time that *electricity storage participants* and *electricity storage facilities* are more fully integrated under these *market rules.*

21.2 Market Registration

21.2.1 This section 21.2 applies for the purposes of the market registration process set out in Section 2.2 of this Chapter 7.

21.2.2 An *electricity storage participant* wishing to register an *electricity storage facility* as a *self-scheduling electricity storage facility*, shall:

21.2.2a register all *electricity storage units* associated with that *electricity storage facility* as *self-scheduling generation units* to inject electricity;

21.2.2b register all electricity storage units associated with that same *electricity storage facility* as *non-dispatchable loads* to withdraw electricity; and

21.2.2c fulfill all other applicable requirements for market registration relating to *self-scheduling generation facilities* and *non-dispatchable loads*, including those requirements set out in Appendix 4.24 of Chapter 4 (IESO Monitoring Requirements: Electricity Storage Facilities) and Appendix 4.25 of Chapter 4 (Monitoring Requirements: Electricity Storage Performance Standards)".

21.2.3 Subject to the *market rules* governing participation in the *energy* markets and the provision of *ancillary services* to the *IESO,* a *self-scheduling electricity storage facility* may only be registered to participate in the *energy market* and to provide *reactive support service*, *voltage control service*, or *regulation* service or combinations of the foregoing, except that it shall not be registered to both participate in the *energy market* and provide *regulation* service.

21.2.4 An *electricity storage participant* wishing to register an *electricity storage facility* as a dispatchable *electricity storage facility*, in addition to the requirements for market registration outlined elsewhere in the *market rules* pertaining to the facility types referenced below, shall:

21.2.4a register all *electricity storage units* associated with that *electricity storage facility* as dispatchable *generation units* to inject electricity;

21.2.4b register all *electricity storage units* associated with the same *electricity storage facility* as *dispatchable loads* to withdraw electricity; and

21.2.4c fulfill all other applicable requirements for market registration relating to dispatchable *generation units* and *dispatchable loads*, including those requirements set out in Appendix 4.24 of Chapter 4 (IESO Monitoring Requirements: Electricity Storage Facilities) and Appendix 4.25 of Chapter 4 (Monitoring Requirements: Electricity Storage Performance Standards).

21.2.5 Subject to the *market rules* governing participation in the *energy* markets and the provision of *ancillary services* to the *IESO,* a dispatchable *electricity storage facility* may only be registered to provide *energy*, *operating reserve, reactive support service* or *voltage control service*, or combinations of the foregoing and may participate in the *capacity auction.*

21.3 Provision of Regulation Service

21.3.1 An e*lectricity storage participant* wishing to provide *regulation* services must register its *electricity storage facility* as a *self-scheduling electricity storage facility* as set forth in section 21.2.2, but excluding section 21.2.2b.

21.3.2 Notwithstanding section 2.2.9A.1, an *electricity storage participant* may apply to register as a *self-scheduling electricity storage facility* any *electricity storage facility* that has an e*lectricity storage capacity* greater than 10 MW up to 50 MW in capacity for the purposes of providing *regulation services* only, provided that the *IESO* determines that there are no adverse impacts on the reliable operation of the *IESO-controlled grid*;

21.3.3 An *electricity storage facility* that is registered to provide *regulation services* may not participate in the *energy* market or the *operating reserve* market.

21.4 Day-Ahead - Energy Offers and Energy Bids

21.4.1 In addition to submitting either an *offer* to inject *energy* or a *bid* to withdraw *energy* as part of the day-ahead commitment process, an *electricity storage*

participant may also submit both an *offer* to inject *energy* and a *bid* to withdraw *energy* for a single dispatchable *electricity storage unit* for the same *dispatch hour*.

21.4.2 For each *dispatch hour* in which both *energy offers* and *bids* are submitted in accordance with section 21.4.1, the *electricity storage participant* shall ensure that the lowest price of the *offers* submitted for that *electricity storage unit* to inject *energy* is greater than the highest price of any *bid* for that same *electricity storage unit* to withdraw *energy.*

21.5 Real Time Energy Offers and Energy Bids

21.5.1 Notwithstanding section 3.5.1, an *electricity storage participant* that is registered and wishes to submit *energy offers* or *energy bids* relating to a dispatchable *electricity storage unit* may submit both an *offer* to inject *energy* and a *bid* to withdraw *energy* for that *electricity storage unit* during the same *dispatch hour*.

21.5.2 For each *dispatch hour* in which both *energy offers* and *bids* are submitted in accordance with section 21.4.1, the *electricity storage participant* shall ensure that the lowest price of the *offers* submitted for that *electricity storage unit* to inject *energy* is greater than the highest price of any *bid* for that same *electricity storage unit* to withdraw *energy*.

21.5.3 An *electricity storage provider* whose lowest *offer* price for an *electricity storage unit* to inject *energy* in any *dispatch hour* is less than or equal to its highest *bid* price for the same *electricity storage unit* to withdraw *energy* in that same *dispatch hour* is not entitled to congestion management *settlement* credit determined in accordance with section 3.5.2 of Chapter 9 in respect of that *dispatch hour*, and if paid the *IESO* may recover such inappropriate congestion management *settlement* credit in accordance with section 3.5.6E of Chapter 9

21.6 Revisions to Dispatch Data

21.6.1 Notwithstanding section 3.3.5, the *IESO* shall approve reduced injections or withdrawal amounts included in revised *dispatch data* from *electricity storage participants* submitted within 2 hours of a given *dispatch hour,* up to a closing time stipulated in the applicable *market manual*, where the *electricity storage participant* determines, acting reasonably that its *electricity storage unit* may reach its:

21.6.1a. *lower energy limit* in that *dispatch hour*, and will likely prevent the *electricity storage unit* from injecting *energy* in accordance with its *offer*; or

21.6.1.b *upper energy limit* in that *dispatch hour*, and will likely prevent the *electricity storage unit* from withdrawing *energy* in accordance with its *bid*.

21.7 Operating Reserve

21.7.1 An *electricity storage participant* shall not offer *operating reserve* from a dispatchable *electricity storage facility* in any *dispatch hour* when there is a simultaneous *energy* bid and *energy* offer in the real-time market for that facility in the same dispatch hour.

21.7.2 An electricity storage participant shall only *offer operating reserve* from the *electricity storage unit* registered as a dispatchable *generation unit* to represent its injection capabilities pursuant to Section 21.2.2a if:

21.7.2.1 the dispatchable *electricity storage unit* is exclusively *offered* as a dispatchable *generation unit* for the entire *dispatch hour*;

21.7.2.2 the dispatchable *electricity storage unit* registered as a *dispatchable load* shall not *bid* to withdraw *energy* from the *real-time market* nor *offer operating reserve* in the subsequent *dispatch hour*; and

21.7.2.3 the *remaining duration of service* at the time stipulated in the applicable *market manual* is greater than or equal to the period of time stipulated in the applicable *market manual.*

21.7.3 An *electricity storage participant* shall only offer *operating reserve* from the *electricity storage* unit registered as a *dispatchable load* to represent its withdrawal capabilities pursuant to Section 21.2.2b if:

21.7.3.1 The dispatchable *electricity storage unit* is exclusively bid as a *dispatchable load* for the entire *dispatch hour*;

21.7.3.2 The dispatchable *electricity storage unit* registered as a dispatchable *generator* shall not offer to inject *energy* in the *real-time market* nor offer *operating reserve* in the subsequent *dispatch hour*; and

21.7.3.3 The *remaining duration of service* at the time stipulated in the applicable *market manual* is greater than or equal to a period of time stipulated in the applicable *market manual.*

21.8 Interpretation

21.8.1 To the extent of any conflict or inconsistency between the provisions of this

section 21 and any other provisions of the *market rules*, the provisions of this section 21 shall govern.

21.8.2 With respect to Chapter 7, System Operations and Physical Markets-Appendices, the *IESO* will, acting reasonably and consistently at all times with the scope and intent of the amendments referenced in section 21.1:

21.8.2a treat electricity storage injecting, or proposing to inject *energy*, as either a dispatchable or self-scheduling generation resource; and

21.8.2b treat electricity storage withdrawing, or proposing to withdraw *energy*, as either a *dispatchable load* or *non-dispatchable load*, in each case, deeming such changes to be made to the applicable provisions of such Appendices or applicable *market manuals* as may be necessary to give full meaning to the foregoing.

21.8.3 For further certainty, the reference in section 21.7.2a to the use of dispatchable or self-scheduling generation resources in the interpretation of Chapter 7, System Operations and Physical Markets-Appendices and the applicable *market manuals*, shall not include any features or attributes that pertain primarily to and are distinctive of *intermittent generators, flexible nuclear generators, variable generators,* or *transitional scheduling generators*.

Exhibit “N”

Chapter 9 of the IESO Market Rules issued November 29, 2023

Exhibit “N”

to the Affidavit of Robin Doolittle

Sworn before me on October 29, 2025, in accordance with O. Reg. 431/20, Administering Oath or Declaration Remotely



Commissioner for Taking Affidavits
(or as may be)

October 29, 2025

Keith Edward Hickey, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.

Expires June 24, 2027.

Market Rules

Chapter 9
Settlements and Billing

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1. Introductory Rules

1.1 Application and Purpose

1.1.1 This chapter applies to:

1.1.1.1 the *IESO*; and

1.1.1.2 *market participants*.

1.1.2 This chapter sets out the respective rights and obligations of the *IESO* and of *market participants* in determining, billing for and effecting payment in respect of financial obligations arising from the *IESO-administered markets*, other provisions of the *market rules*, and *applicable law* including without limitation the *Electricity Act, 1998,* the *Ontario Energy Board Act, 1998*, and any regulations enacted thereunder including, but not limited to the following:

1.1.2.1 [Intentionally left blank – section deleted]

1.1.2.2 the *energy market*;

1.1.2.3 the *operating reserve market*;

1.1.2.4 congestion management*;*

1.1.2.5 *transmission rights* (*TRs*);

1.1.2.6 [Intentionally left blank – section deleted]

1.1.2.7 operating deviations;

1.1.2.8 *ancillary services* and *reliability must-run contracts*;

1.1.2.9 *transmission services charges* and connection charges collected by the *IESO*;

1.1.2.10 [Intentionally left blank – section deleted]

1.1.2.11 the *IESO* administration charge;

1.1.2.12 penalties and fines;

1.1.2.13 [Intentionally left blank – section deleted]

1.1.2.14 rebates and other payments arising from market power mitigation measures;

1.1.2.15 the day-ahead commitment process;

1.1.2.16 forecasting services relating to *variable generation*;

1.1.2.17 *capacity obligations*; and

1.1.2.18 ramp-down *settlement* amount.

1.2 Regulated Settlement Amounts and Related Payment Charges

1.2.1 Notwithstanding any other provision within the *market rules*, the *IESO* shall, with respect to determining, collecting and remitting applicable *settlement amounts*, comply with the relevant provisions of *applicable law* including without limitation the *Electricity Act, 1998*, the *Ontario Energy Board Act, 1998*, and any regulations enacted thereunder, as amended from time to time.

1.2.1.1 [Intentionally left blank – section deleted]

1.2.1.2 [Intentionally left blank – section deleted]

1.2.2 [Intentionally left blank – section deleted]

1.2.3 Notwithstanding any other provision within the *market rules*, *market participants* shall remit to the *IESO* such applicable *settlement amounts* and other payments as may be required under the relevant provisions of *applicable law* including without limitation the *Electricity Act, 1998*, the *Ontario Energy Board Act, 1998* and any regulations enacted thereunder, as amended from time to time.

1.2.3.1 [Intentionally left blank – section deleted]

1.2.3.2 [Intentionally left blank – section deleted]

2. Settlement Data Collection and Management

2.1 Metering and Metering Responsibilities

2.1.1 Subject to section 2.1.1A, every *meter* utilised for determining *settlement amounts* according to this Chapter must be a *registered wholesale meter (RWM).*

2.1.1A Nothing in section 2.1.1 shall be construed as requiring the *IESO* to determine *settlement amounts* on the basis of an *RWM* in circumstances where:

2.1.1A.1 it is permitted to use another *meter* for this purpose pursuant to section 3.1.4A;

2.1.1A.2 in circumstances where the *IESO* has determined that determination of *settlement amounts* using a *metering installation* whose registration has expired is required for the efficient operation of the *IESO-administered markets*;

2.1.1A.3 [Intentionally left blank – section deleted]

2.1.1A.4 the *IESO* has not permitted the use of the *RWM* for determining *settlement amounts* for the reason specified section 4.2.2A of Chapter 6;

2.1.1A.5 [Intentionally left blank – section deleted]

2.1.1A.6 the *IESO* is determining *settlement amounts* related to *capacity obligations* using measurement data submitted by *capacity market participants* with an *hourly demand response resource*.

2.1.2 A single *metered market participant* must be designated for each *RWM* that is not an *intertie metering point*.

2.1.3 The same *metered market participant* must be designated for all *primary RWMs,* other than *intertie metering points*, for which any *metering data* will be allocated to any single *registered facility*.

2.1.4 [Intentionally left blank – section deleted]

2.1.5 The *IESO* shall be responsible for *metering data* and its allocation with respect to all *intertie metering points*. The *IESO*, in accordance with operating agreements with other *control areas*, shall:

2.1.5.1 to the extent required to fulfill its obligations under this Chapter, interpret and apply the protocols governing interchanges between the *IESO-controlled grid* and other *control areas*;

2.1.5.2 provide to the *settlement process* the *interchange schedule data* described in section 2.5; and

2.1.5.3 determine the allocated quantities called for by section 3.1.9 based on scheduled *intertie* flows even when these differ from actual flows as determined by *metering data*.

2.1.6 [Intentionally left blank – section deleted]

2.1.6.1 [Intentionally left blank]

2.1.6.2 [Intentionally left blank]

2.1A Station Service

2.1A.1 The *market participant* responsible for registering a *facility* consuming *transmission station service* or *connection station service* shall:

2.1A.1.1 identify to the *IESO* the fraction of the *energy* withdrawn at that *facility* supplied from the *IESO-controlled grid* which is not such *station service*; and

2.1A.1.2 ensure that the consumption of the *energy* referred to in section 2.1A.1.1 is measured by an *RWM* that complies with the requirements of Chapter 6.

2.1A.2 For *settlement* purposes, *transmission station service* shall be treated as a transmission loss.

2.1A.3 Where *connection station service* is not separately metered by an *RWM*, the *energy* consumption associated with *connection station service* shall be estimated and submitted by the *market participant* responsible for registering the relevant *connection facility* in accordance with the equations and procedures described in the applicable *market manuals*, which estimate shall be stamped by a registered professional engineer and shall be subject to audit by the *IESO.*

2.1A.4 For *settlement* purposes, *connection station service* shall be treated as follows:

2.1A.4.1 where the *energy consumption* associated with *connection station service* is included in the *energy consumption* measured by an *RWM*, the sum of

the *energy* associated with that *connection station service* and with site specific losses shall be apportioned:

a. amongst those *market participants* whose *facilities* are *connected* to the relevant *connection facility* in the proportions provided by the *metering service provider* for that *RWM*, and the provision of such proportions shall constitute certification by such *metering service provider* that such proportions have been agreed between the *metering service provider* and all *market participants* whose *facilities* are *connected* to the relevant *connection facility*.

b. [Intentionally left blank – section deleted]

2.1A.4.2 where the *energy consumption* associated with *connection station service* is not included in the *energy consumption* measured by an *RWM*, the sum of the *energy* associated with that *connection station service* and with site specific losses shall be apportioned:

a. amongst those *market participants* whose *facilities* are connected to the relevant *connection facility* in the proportions provided by the *metering service provider* for each *RWM* measuring the flow of *energy* taken from the *connection facility*. The proportions provided by each *metering service provider* shall reflect agreement amongst all applicable *metering service providers* and shall only be accepted by the *IESO* if the proportions provided by all applicable *metering service providers* sum to one. The provision of such proportions shall constitute certification by each such *metering service provider* that it has reached agreement with all other applicable *metering service providers* in respect of such proportions; or

b. where one or more of the *metering service providers* referred to in section 2.1A.4.2(a) has not provided the *IESO* with the proportions referred to in that section, amongst those *market participants* whose *facilities* are connected to the relevant *connection facility* on the basis of the number of *load serving breakers* serving each such *market participant.*

2.1A.5 A *metering service provider* who provides to the *IESO* factors for apportioning *connection station service* and site specific losses pursuant to section 2.1A.4.1(a) or 2.1A.4.2(a) may, no more than once in each calendar year or more frequently if required by the registration of a new *RWM*, submit to the *IESO* revised proportions for the purposes of apportioning the *energy* referred to in section 2.1A.4. The provision of such revised proportions shall constitute certification by

such *metering service provider* as to the agreement referred to in section 2.1A.4.1(a) or 2.1A.4.2(a), as the case may be.

2.1A.6 For greater certainty, nothing in section 2.1A.4 shall be construed as permitting the apportionment of *connection station service* and site specific losses to a *market participant* in respect of a *facility* that is an *embedded load facility,* an *embedded generation facility,* or an *embedded electricity storage facility.*

2.1A.6A Where the sum of *energy* associated with *connection station service* and with site specific losses is apportioned by the *IESO* pursuant to section 2.1A.4.2(b) by reason of the failure of all applicable *metering service providers* to reach agreement as to the proportions referred to in sections 2.1A.4.1(a) or 2.1A.4.2(a) as the case may be, any *market participant* that is the subject of such apportionment may submit the matter to the dispute resolution process set forth in section 2 of Chapter 3 and shall, in the *notice of dispute*:

2.1A.6A.1 name all other *market participants* which are the subject of the same apportionment as *respondents*; and

2.1A.6A.2 request that the arbitrator determine an alternative apportionment.

2.1A.6B Where an *arbitrator* determines an alternative apportionment pursuant to section 2.1A.6A, the *metering service provider* for each applicable *RWM* shall, within 5 *business days* of the date of the award of the *arbitrator*, file with the *IESO* proportions for apportioning the sum of *energy* associated with *connection station service* and with site specific losses that reflect such alternative apportionment.

2.1A.7 Subject to section 2.1A.9, where *metering data* from a *metering installation* does not reflect the amount of *energy* injected by a *generation unit* passing through the *metering installation* net of all applicable *generation station service*, the costs associated with *generation station service* shall, for *settlement* purposes, be apportioned:

2.1A.7.1 amongst those *generation units* consuming such *generation station service* in the proportions provided by the *metering service provider* for the relevant *metering installation*; or

2.1A.7.2 where the *metering service provider* has not provided the proportions referred to in section 2.1A.7.1, equally amongst all such *generation units*,

provided that, in either case such apportionment results in a totalization of the applicable *RWMs* that is identical to the totalization of the *meters* required to meet the monitoring requirements of section 7.3, 7.3A, 7.4, 7.5 or 7.6, as the case may be, of Chapter 4.

2.1A.7A Subject to section 2.1A.9A, where *metering data* from a *metering installation* does not reflect the amount of *energy* injected by an *electricity storage unit* passing through the *metering installation* net of all applicable *electricity storage station service*, the costs associated with *electricity storage station service* shall, for *settlement* purposes, be apportioned:

2.1A.7A.1 amongst those electricity storage units consuming such electricity storage station service in the proportions provided by the metering service provider for the relevant metering installation; or

2.1A.7A.2 where the *metering service provider* has not provided the proportions referred to in section 2.1A.7A.1, equally amongst all such *electricity storage units*, provided that, in either case such apportionment results in a totalization of the applicable *RWMs* that is identical to the totalization of the *meters* required to meet the monitoring requirements of section 7.3, 7.3A, 7.4, 7.5 or 7.6, as the case may be, of Chapter 4.

2.1A.8 A *metering service provider* who provides the *IESO* with proportions pursuant to section 2.1A.7.1 may submit up to two requests in a calendar year to the *IESO* to have such proportions revised, provided that the giving of effect to such revisions shall be subject to the mutual agreement of the *metering service provider* and the *IESO*.

2.1A.9 If the consumption of *generation station service* results in:

2.1A.9.1 an allocated quantity of *energy* withdrawn or AQEW, as described in section 3.1.9, accruing at the location of a *generation unit* which is part of an eligible *generation facility* within the meaning of section 2.1A.13 in circumstances where the injection of *energy* by that *generation facility* as a whole exceeds the withdrawal of *energy* by that *generation facility* as a whole during a given *metering interval*; and

2.1A.9.2 such accrual of AQEW results in *hourly uplift,* non-hourly *settlement amounts,* or both, accruing at the location referred to in section 2.1A.9.1 during any *metering interval* within an *energy market billing period*, the *metered market participant* for that *generation facility* shall, subject to section 2.1A.10, be reimbursed the *hourly uplift* and non-hourly *settlement amounts* referred to in section 2.1A.9.2.

2.1A.9A If the consumption of *electricity storage station service* results in:

2.1A.9A.1 an allocated quantity of *energy* withdrawn or AQEW, as described in section 3.1.9, accruing at the location of an *electricity storage unit* which is part of an eligible *electricity storage facility* within the meaning of

section 2.1A.13A in circumstances where the injection of *energy* by that *electricity storage facility* as a whole exceeds the withdrawal of *energy* by that *electricity storage facility* as a whole during a given *metering interval*; and

2.1A.9A.2 such accrual of AQEW results in *hourly uplift,* non-hourly *settlement amounts,* or both, accruing at the location referred to in section 2.1A.9.1 during any *metering interval* within an *energy market billing period*, the *metered market participant* for that *electricity storage facility* shall, subject to section 2.1A.10, be reimbursed the *hourly uplift* and non-hourly *settlement amounts* referred to in section 2.1A.9A.2.

2.1A.10 No reimbursement will be provided to a *metered market participant* pursuant to section 2.1A.9 or 2.1A.9A in respect of amounts attributable to the following:

2.1A.10.1 transmission services charges;

2.1A.10.2 any applicable penalties, awards or adjustments reflected in the *invoice* issued to the *metered market participant*; or

2.1A.10.3 any other *settlement amounts* where such a reimbursement:

a. is prohibited by *applicable law* or the *market rules*; or

b. where the *settlement amount* is collected by the *IESO* pursuant to an obligation imposed upon it by *applicable law,* is not permitted by such *applicable law.*

2.1A.11 [Intentionally left blank – section deleted]

2.1A.12 [Intentionally left blank – section deleted]

2.1A.13 For the purposes of section 2.1A.9.1, a *generation facility* may be designated by the *IESO* as an eligible *generation facility* where the *generation facility*:

2.1A.13.1 is comprised of two or more *registered facilities*:

a. [Intentionally left blank – section deleted]

b. that have the same metered market participant.

2.1A.13.2 is located within the *IESO control area*; and

2.1A.13.3 has associated with it *generation station service* that serves more than one *registered facility* included within that *generation facility*.

2.1A.13A For the purposes of section 2.1A.9A.1, an *electricity storage facility* may be designated by the *IESO* as an eligible *electricity storage facility* where the *electricity storage facility*:

2.1A.13A.1 is comprised of two or more *registered facilities* that have the same metered market participant;

2.1A.13A.2 is located within the *IESO control area*; and

2.1A.13A.3 has associated with it *electricity storage station service* that serves more than one *registered facility* included within that *electricity storage facility*.

2.1A.14 The *IESO* shall recover any amount reimbursed pursuant to section 2.1A.9 or 2.1A.9A described in section 4.8.1.6.

2.2 Metering Data Recording and Collection Frequency

2.2.1 All *metering data* must be recorded for each *metering interval* except as otherwise provided in section 2.2.2 or elsewhere in these *market rules.*

2.2.2 A *RWM* that serves only *non-dispatchable load, self-scheduling generation facilities, self-scheduling electricity storage facilities, transitional scheduling generators* or *intermittent generators* need not record any *metering data* regarding *energy* (in MWh) or reactive *energy* (in MVARh) for *metering intervals* but must record such *metering data* for each *settlement hour*. *Metering data* regarding demand or power (in MW) shall be recorded by such *RWMs* for such *intervals* as the *IESO* may specify in the applicable *market manual*.

2.2.3 An *intertie metering point* shall record *metering data* in a manner consistent with the applicable interchange protocol.

2.2.4 *Metering data* shall be collected by or delivered to the *IESO* in accordance with Appendix 9.1 or in accordance with such other schedule as the *IESO* may determine from time to time.

2.3 Collection and Validation of Metering Data

2.3.1 The *IESO* shall collect or receive *metering data* directly from *RWM*s, in such other manner as may be specified in Appendix 9.1 and from such other processes as may be appropriate. Such *metering data* will initially be "raw" data that have not been validated or corrected by the *VEE process.*

2.3.2 The raw *metering data* collected by or delivered to the *IESO* shall be subjected to the *VEE process* described in Appendix 9.1. The *VEE process* shall:

2.3.2.1 convert raw *metering data* into validated, corrected or estimated "*settlement* ready" *metering data* suitable for use in determining *settlement amounts*;

2.3.2.2 operate according to the *settlement* schedule specified in section 6;

2.3.2.3 detect errors in *metering data* resulting from improper operational conditions and/or hardware/software malfunctions, including failures of or errors in metering or communication hardware, and from *metering data* exceeding pre-defined variances or tolerances; and

2.3.2.4 use operational system data, including historical generation and load patterns and data collected by or delivered to the *IESO*, as appropriate, for validating raw *metering data*, and for editing, estimating and correcting *metering data* found to be erroneous or missing.

2.3.2A While undergoing the *VEE process, metering data* from a given registered *metering installation* in respect of a given *trading day* or, where applicable, estimates thereof, shall bear appropriate flags and shall be accessible by electronic means by any person referred to in section 10.1.3 of Chapter 6 on the day following such *trading day.*

2.3.3 Subject to section 2.3.4, all *metering data* in respect of a given registered *metering installation* for a given *trading day* used for determining *settlement amounts* pursuant to this Chapter shall be "*settlement* ready" *metering data* that has been validated and corrected by the *VEE process*. Such "*settlement* ready" *metering data* shall be accessible by electronic means by any person referred to in section 10.1.3 of Chapter 6 no later than five *business days* following such *trading day*, providing that the applicable *metering service provider* has resolved any trouble call pertaining to such *metering data.*

2.3.4 *Metering data* used for determining *settlement amounts* pursuant to this Chapter shall, where applicable, be adjusted to reflect the estimation or deeming provisions set forth in sections 11.1.4 and 11.1.6, respectively, of Chapter 6.

2.4 [Intentionally left blank – section deleted]

2.4.1 [Intentionally left blank – section deleted]

2.4.1.1 [Intentionally left blank]

2.4.1.2 [Intentionally left blank]

2.4.1.3 [Intentionally left blank]

2.4.1.4 [Intentionally left blank]

2.4.2 [Intentionally left blank – section deleted]

2.4.2.1 [Intentionally left blank – section deleted]

a. [Intentionally left blank – section deleted]

b. [Intentionally left blank – section deleted]

2.4.2.2 [Intentionally left blank – section deleted]

2.4.3 [Intentionally left blank – section deleted]

2.4.3.1 [Intentionally left blank – section deleted]

2.4.3.2 [Intentionally left blank – section deleted]

2.4.4 [Intentionally left blank – section deleted]

2.4.5 [Intentionally left blank – section deleted]

2.4.5.1 [Intentionally left blank – section deleted]

a. [Intentionally left blank – section deleted]

b. [Intentionally left blank – section deleted]

c. [Intentionally left blank – section deleted]

d. [Intentionally left blank – section deleted]

2.4.5.2 [Intentionally left blank – section deleted]

2.4.6 [Intentionally left blank – section deleted]

2.4.7 [Intentionally left blank – section deleted]

2.4.7.1 [Intentionally left blank – section deleted]

2.4.7.2 [Intentionally left blank – section deleted]

2.4.8 [Intentionally left blank – section deleted]

2.4.9 [Intentionally left blank – section deleted]

2.4.9.1 [Intentionally left blank – section deleted]

2.4.9.2 [Intentionally left blank – section deleted]

a. [Intentionally left blank – section deleted]

b. [Intentionally left blank – section deleted]

2.4.10 [Intentionally left blank – section deleted]

2.4.11 [Intentionally left blank – section deleted]

2.4A Delivery Points

2.4A.1 The *delivery point* for a given *RWM* shall be determined by the *IESO* in accordance with:

2.4A.1.1 adjusting the *metering data* from that *RWM* in accordance with section 4.2.3 of Chapter 6; and

2.4A.1.2 summing the *metering data* from that *RWM* with *metering data* from all other applicable *RWMs* in accordance with the applicable totalization table comprised in the relevant *meter point* documentation submitted in respect of that *RWM* pursuant to section 1.3 of Appendix 6.5 of Chapter 6.

2.4A.2 For the purposes of the determination of the *settlement amounts* referred to in sections 3, 4 and 5, all references to an *RWM*, an *RWM* m or a *registered facility* k/m shall be deemed to be a reference to the *delivery point* associated with:

2.4A.2.1 the *RWM*; or

2.4A.2.2 the *RWM* or *RWMs* associated with the *registered facility*,

as the case may be.

2.5 Collection of Interchange Schedule Data

2.5.1 The *IESO* shall, in co-operation with other *control area operators, security coordinators* and *interconnected transmitters* and in accordance with applicable interchange protocols, determine the following *interchange schedule data* for each *settlement hour*:

2.5.1.1 the total scheduled flows of *energy*, and of any other physical quantity or *physical service* traded in the *IESO-administered markets*, across each

transmission interface between the *IESO-controlled grid* and an *intertie zone*; and

2.5.1.2 the allocation of each scheduled *intertie* flow among *market participants*.

2.5.2 The *IESO settlement process* shall use the *interchange schedule data* to determine *settlement amounts* even though the total scheduled flows on all *interties* may be either more or less than actual physical flows as measured by all *intertie metering points*. The *IESO* shall manage deviations between scheduled and actual *intertie* flows in accordance with interchange protocols with other *control areas* and the requirements of applicable *standards authorities*, with any resulting financial gains or losses ultimately accruing or charged to *market participants* through the *hourly uplift***.**

2.5.3 The *IESO* shall *publish* the total scheduled and actual flows of *energy* between the *IESO-controlled grid* and each *intertie zone*.

2.6 Collection of Physical Bilateral Contract Data

2.6.1 Any selling *market participant* may, under the provisions of Chapter 8, submit to the *IESO physical bilateral contract data* that define *physical bilateral contract quantities* of *energy* that it is selling to a specified buying *market participant* in specified hours and at specified primary *RWMs* or *intertie metering points*.

2.6.2 *Physical bilateral contract quantities* shall not be included in the quantities of *energy* used to determine *settlement amounts* related to *energy*, although they may be used to determine other *settlement amounts* as provided in this Chapter.

2.6.3 *Physical bilateral contract quantities* must specify total quantities for each *settlement hour*, not quantities for metering intervals within a *settlement hour*. The *IESO* shall divide hourly *physical bilateral contract quantities* into equal interval quantities when necessary for determining *settlement amounts* as provided for in section 3.1.6.

2.6.4 The *IESO* shall submit directly to the *settlement process* the *physical bilateral contract quantities* submitted by each *market participant* for each *settlement hour* as provided in section 3.1.6.

2.7 Collection of Transmission Right (TR) Data

2.7.1 The *IESO* shall implement, in accordance with Chapter 8, *TR auctions* that will result in an allocation among *market participants* of *transmission rights)* associated with the transactions referred to in section 4.1.1.1 of Chapter 8 and conveying rights to *settlement amounts* based on differences in *energy* prices

between the specified injection *TR zone* and the specified withdrawal *TR zone* with which each *TR* is associated.

2.7.2 The *IESO* shall submit to the *settlement process* by the sixth *business day* after each *dispatch day* the following data related to *TRs*:

2.7.2.1 the quantities, in MW, of *TRs* held by each *TR holder* with respect to each applicable pair of specified injection and withdrawal *TR* zones for each *settlement hour* of such *dispatch day*; and

2.7.2.2 the total proceeds from the sale of *TR*s in respect of all rounds of a *TR auction* that is concluded on such *dispatch day*.

2.8 [Intentionally left blank – section deleted]

2.8.1 [Intentionally left blank – section deleted]

2.8.2 [Intentionally left blank – section deleted]

2.8.3 [Intentionally left blank – section deleted]

2.9 Collection of Ancillary Service Data

2.9.1 The *IESO* shall submit to the *settlement process* the data from *contracted ancillary service* contracts and from the daily *dispatch* process necessary to determine *contracted ancillary service* payments.

2.10 Collection of Market Price and Other Settlement Data

2.10.1 The *IESO* shall submit to the *settlement process* all *market prices* determined by the *IESO* according to the provisions of Chapter 7, and all *metering data* and other *operating results* available to the *IESO* as may be needed by the *settlement process* for determining *settlement amounts* pursuant to this Chapter.

2.11 Settlement Record Retention, Confidentiality, and Reliability

2.11.1 Subject to section 2.11.3, the *IESO* shall retain all *settlement* records for a period adequate to support the *settlement* audit referred to in section 6.19, matters described in section 6.8.12.4, and/or a *dispute outcome*, but in no case for less than seven years.

2.11.2 The *IESO* shall periodically review the period for which *settlement* records are retained and shall, if required and subject to section 2.11.3, take such steps as may be required to effect a change in such period.

2.11.3 The period for which *settlement* records are retained shall comply with the requirements of any regulatory authority having jurisdiction over the *IESO* or *market participants*.

2.11.4 *Settlement* and supporting data for each *trading day* of a *billing period* shall be made available by direct electronic means to the relevant *market participant* as soon as the data become available to the *IESO*. The data shall remain available via electronic access until the earlier of 60 days from the end of the *billing period* and the date on which invoicing and payment activities for that *billing period* have been completed.

2.11.5 The *IESO* shall safeguard any *settlement* information that is *confidential information* in accordance with section 5 of Chapter 3.

2.11.6 The *IESO* shall assure that back-up computer and communication systems are available for the *settlement process* and shall, in accordance with section 6.1, use such back-up systems in the event that equipment failure or an emergency evacuation makes the primary systems referred to in section 6.1.1 unavailable.

3. Determination of Hourly Settlement Amounts

3.1 Hourly Settlement Variables and Data

3.1.1 The *IESO* shall determine hourly *settlement amounts* for the *hourly markets* using the hourly price and quantity variables and data described in this section 3.1.

3.1.2 [Intentionally left blank – section deleted]

Day-Ahead Commitment Process Variables, Data and Information

3.1.2A The *IESO* shall determine the following day-ahead quantities from the *schedule of record,* and provide them directly to the *settlement process*:

$DA_DQSI_{k,h}^{i,t}$ = *schedule of record* quantity scheduled for injection by *market participant* 'k' for an import transaction at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h'

$DA_DQSI_{k,h}^{m,t}$ = *schedule of record* quantity scheduled for injection by *market participant* 'k' at *delivery point* 'm' during *metering interval* 't' of *settlement hour* 'h'

$DA_DQSW_{k,h}^{i,t}$ = *schedule of record* quantity scheduled for withdrawal by *market participant* 'k' for an export transaction at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h'

$DA_ELMP_{h}^{m,t}$ = day-ahead constrained schedule intertie price at the *delivery point* 'm' of the sink for the export transaction during *metering interval* 't' of *settlement hour* 'h'

$DA_ILMP_{h}^{m,t}$ = day-ahead constrained schedule intertie price at the *delivery point* 'm' of the source for the import transaction during *metering interval* 't' of *settlement hour* 'h'

3.1.2B The *IESO* shall provide directly to the *settlement process*:

3.1.2B.1 information to identify *market participants* which are deemed to have accepted in accordance with section 5.8.4 of Chapter 7 a day-ahead production cost guarantee for their *generation facility*;

3.1.2B.2 information to identify any event in which the *IESO* de-commits a *generation facility* between the release and *publication* of the *schedule of record* and the end of its committed schedule in the *schedule of record* where the *market participant* has been deemed to have accepted in accordance with section 5.8.4 of Chapter 7 a day-ahead production cost guarantee for that *facility*;

3.1.2B.3 exemptions from the day-ahead import failure charge described in section 3.8B, for any applicable import transactions scheduled in the *schedule of record* where such exemptions have been determined in accordance with chapter 7, section 7.5.8B;

3.1.2B.4 exemptions from the day-ahead export failure charge described in section 3.8D, for any applicable export transactions scheduled in the *schedule of record* where such exemptions have been determined in accordance with chapter 7, section 7.5.8B;

3.1.2B.5 exemptions from the day-ahead linked wheel failure charge described in section 3.8E, for any applicable linked wheel transactions scheduled in the *schedule of record* where such exemptions have been determined in accordance with chapter 7, section 7.5.8B; and

3.1.2B.6 exemptions from the day-ahead *generator* withdrawal charge described in section 3.8F, for any applicable *registered facility* scheduled in the *schedule of record* where such exemptions have been determined in accordance with chapter 7, section 7.5.3.

3.1.2B.7 the following information:

$DA_BE_{k,h}^{m,t}$ = *energy offers* submitted in day-ahead, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *delivery point* 'm' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered price in each *price quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2

$DA_BE_{k,h}^{i,t}$ = *energy offers* submitted in day-ahead, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered price in each *price quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2

$DA_BL_{k,h}^{i,t}$ = *energy bids* submitted in day-ahead, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered price in each *price quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2

$DA_SNLC_{k,h}^{m}$ = as-offered speed-no-load cost associated with *three-part offers* for a given *settlement hour* 'h' for *market participant* 'k' at *delivery point* 'm'

$DA_SUC_{k,h}^{m}$ = as-offered *start-up cost* associated with *three-part offers* for a given *settlement hour* 'h' for *market participant* 'k' at *delivery point* 'm'

$MLP_{k,h}^{m,t}$ = minimum output of *energy* the *market participant* 'k' at *delivery point* 'm' can maintain without ignition support in *metering interval* 't' of *settlement hour* 'h'

$OPCAP_{k,h}^{m,t}$ = de-rated *generation capacity* submitted by *market participant* 'k' at *delivery point* 'm' in *metering interval* 't' of *settlement hour* 'h'

3.1.2C The *IESO* shall determine from the *pre-dispatch schedule* and the *pre-dispatch* projected *market schedule,* and provide directly to the *settlement process* the following *pre-dispatch prices* and quantities:

$PD_DQSI_{k,h}^{i,t}$ = *pre- dispatch* constrained quantity scheduled for injection by *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h'

$PD_DQSW_{k,h}^{i,t}$ = *pre- dispatch* constrained quantity scheduled for withdrawal by *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h'

$PD_EMP_{h}^{m,t}$ = *pre-dispatch* projected *energy market price* applicable to all *delivery points* 'm' in the Ontario zone in *metering interval* 't' of *settlement hour* 'h'

In instances where this variable is provided to the s*ettlement process* on an hourly basis as determined in section 3.9, it shall be deemed to apply uniformly to all *metering intervals* 't' in *settlement hour* 'h'

$PD_ELMP_{h}^{m,t}$ = *pre-dispatch* constrained schedule *intertie* price at the *delivery point* 'm' of the sink for the export transaction during *metering interval* 't' of *settlement hour* 'h'

$PD_ILMP_{h}^{m,t}$ = *pre-dispatch* constrained schedule *intertie* price at the *delivery point* 'm' of the source for the import transaction during *metering interval* 't' of *settlement hour* 'h'

3.1.2D The *IESO* shall provide directly to the *settlement process*:

3.1.2D.1 exceptions from the real-time import failure charge set out in section 3.8C.2 for any applicable import transactions scheduled in the *pre-dispatch schedule* where such exceptions have been determined in accordance with chapter 7, section 7.5.8B;3.1.2D.2 exceptions from the real-time export failure charge set out in section 3.8C.4 for any applicable export transactions scheduled in the *pre-dispatch schedule* where such exceptions have been determined in accordance with chapter 7, section 7.5.8B;

3.1.2D.3 the adjustment of amounts provided for in section 6.6.10A.2 of Chapter 3;

3.1.2D.4 any applicable price bias adjustment factors, as described in section 3.8C.7, utilised in the calculation of the:

a. real-time import failure charge; or

b. real-time export failure charge;

that are in effect as of the *settlement hour* in which such *settlement amounts* are calculated by the *IESO*; and

3.1.2D.5 the following information:

$PD_BE_{k,h}^{i,t}$ = *energy offers* submitted in pre-dispatch, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered price in each *price quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2

$PD_BL_{k,h}^{i,t}$ = *energy bids* submitted in pre-dispatch, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered price in each *price quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2

3.1.3 The *IESO* shall determine *energy market* prices and quantities as provided in Chapter 7 and shall provide the following variables and data from the *energy market,* determined in accordance with section 3.1.4A, directly to the *settlement process*:

$MQSI_{k,h}^{m,t}$ = market quantity scheduled for injection in the *market schedule* by *market participant* 'k' at location m or *intertie metering point* 'm' in *metering interval* 't' of *settlement hour* 'h'

$MQSW_{k,h}^{m,t}$ = market quantity scheduled for withdrawal in the *market schedule* by *market participant* 'k' at location m or *intertie metering point* 'm' in *metering interval* 't' of *settlement hour* 'h'

$DQSI_{k,h}^{m,t}$ = *dispatch* quantity scheduled for injection in the *real-time schedule* by *market participant* 'k' at location m or *intertie metering point* 'm' in *metering interval* 't' of *settlement hour* 'h' determined on the basis of the *dispatch instructions* issued to *market participant* 'k' for that *metering interval*

$DQSW_{k,h}^{m,t}$ = *dispatch* quantity scheduled for withdrawal in the *real-time schedule* by *market participant* 'k' at location m or *intertie metering point* 'm' in *metering interval* 't' of *settlement hour* 'h' determined on

the basis of the *dispatch instructions* issued to *market participant* 'k' for that *metering interval*

$TMQSI_h^{m,t}$ = total market quantity scheduled for injection in the *market schedule* by all *market participant*s at location m or *intertie metering point* 'm' in *metering interval* 't' of *settlement hour* 'h'

= $\sum_k MQSI_{k,h}^{m,t}$, with k = all *market participants*

$EMP_h^{m,t}$ = *energy market* price at *delivery point* 'm' in *metering interval* 't' of *settlement hour* 'h'

$ICP_h^{i,t}$ = where i ∈ M such that M is the set of all *delivery points* 'm' and *intertie metering points* 'm'

$EMP_h^{i,t}$ = *energy market price* at intertie *metering point* 'i' in *metering interval* 't' of *settlement hour* 'h'

= $ICP_h^{i,t} + EMP_h^{m,t}$ subject to the constraints outlined in sections 8.2.2.4 and 8.2.2.5 of Chapter 7.

= where m is any *delivery point* while uniform pricing exists.

= where i ∈ M such that M is the set of all *delivery points* 'm' and *intertie metering points* 'm'.

$HOEP_h$ = hourly Ontario energy price in settlement hour 'h'

= $\sum_{m,t} EMP_h^{m,t}/12$,
with t = all *metering intervals* in *settlement hour* 'h'
m = all *primary RWMs*

$x_h^{m,t}$ = a *settlement* floor price for *energy* applicable to *intertie metering point* 'm' *metering interval* 't' in *settlement hour* 'h', as set in the applicable *market manual*. The need for a *settlement* floor price other than *MMCP* shall remain in effect only until floor prices for *energy offers* from *registered market participants* that are *variable generators* or nuclear *generators* go into effect.

3.1.4 The *IESO* shall determine *operating reserve market* prices and quantities in a process integrated with the *energy market*, as provided in Chapter 7. For each of the two types "r" of *class r reserves*, the *IESO* shall provide directly to the

settlement process the following variables and data, determined in accordance with section 3.1.4A:

$PROR_{r,h}^{m,t}$ = *market price* (in $/MW) of class r reserve in *metering interval* 't' of *settlement hour* 'h' at *delivery point* 'm' or *intertie metering point* 'm'

$PROR_{r,h}^{i,t}$ = *market price* (in $/MW) of class r reserve in *metering interval* 't' of *settlement hour* 'h' at *intertie metering point* 'i'

= where i ∈ M such that M is the set of all *delivery points* 'm' and *intertie metering points* 'm'.

= $ICP_{r,h}^{i,t} + PROR_{r,h}^{m,t}$ subject to the constraints outlined in sections 8.2.2.6 and 8.2.2.7 of Chapter 7.

= where m is any *delivery point* while uniform pricing exists.

$ICP_{r,h}^{i,t}$ = *intertie congestion price* for class r reserve at *intertie metering point* 'i' in *metering interval* 't' of *settlement hour* 'h'

= where i ∈ M such that M is the set of all *delivery points* 'm' and *intertie metering points* 'm'.

$SQROR_{r,k,h}^{m,t}$ = scheduled quantity (in MW) of *class r reserve* for *market participant* 'k' in *metering interval* 't' of *settlement hour* 'h' at location m or *intertie metering point* 'm' as described in the *market schedule*

$DQSR_{r,k,h}^{m,t}$ = dispatch quantity (in MW) of class r reserve for *market participant* 'k' at location m in *metering interval* 't' or *intertie metering point* 'm' of *settlement hour* 'h' as determined on the basis of the *dispatch instructions* issued to *market participant* 'k' for that *metering interval*

3.1.4A For the purposes of sections 3.1.3, 3.1.4 and 3.5.2, "location m" in respect of *market participant* 'k' shall mean the location of:

3.1.4A.1 the relevant *meter* used by *market participant* 'k' to meet the monitoring requirements of section 7.3, 7.4, 7.5 or 7.6, as the case may be, of Chapter 4 in respect of *registered facility* k/m, where such requirements apply in respect of *registered facility* k/m; or

3.1.4A.2 the *RWM* for *registered facility* k/m, where the monitoring requirements of section 7.3, 7.4, 7.5 or 7.6, as the case may be, of Chapter 4 do not apply in respect of *registered facility* k/m.

3.1.5 [Intentionally left blank – section deleted]

3.1.6 *Physical bilateral contract* quantities shall be determined for each *settlement hour* by the *IESO* using *physical bilateral contract* data submitted by selling *market participants* and, where so required by the nature of the *physical bilateral contract* data, operating results. The *IESO* shall divide each *hourly physical bilateral contract* quantity into equal *physical bilateral contract* quantities if determination of settlement amounts requires quantities for each *metering interval* of each *settlement hour*. The *IESO* shall provide the following variables and data directly to the settlement process:

$BCQ_{s,b,h}^{m}$ = *physical bilateral contract quantity* of *energy* (in MWh) sold by selling *market participant* s to buying *market participant* b at primary or intertie *metering point* 'm' in *settlement hour* 'h'

$BCQ_{s,b,h}^{m,t}$ = *physical bilateral contract quantity* of *energy* (in MWh) sold by selling *market participant* s to buying *market participant* b at primary or intertie *metering point* 'm' for each *metering interval* 't' in *settlement hour* 'h'

= $(1/12) \times BCQ_{s,b,h}^{m}$, for all 12 *metering intervals* 't' in *settlement hour* 'h'

3.1.7 The *IESO* shall offer a service whereby the *selling market participant* in a *physical bilateral contract* or the selling *market participant* under a financial bilateral contract may assume responsibility for components of the buying or *buying market participant's settlement* obligations other than those for *energy*.

3.1.8 The *IESO* shall provide the following *TR* data directly to the *settlement process*:

$QTR_{k,h}^{m,n}$ = quantity of *TRs* (in MW) assigned to *market participant* 'k' for transmission from *primary* or *intertie metering point* 'm' to *primary* or *intertie metering point* 'n' for *settlement hour* 'h'

3.1.9 The *IESO* shall determine the following allocated physical quantities for each *market participant* for each *primary RWM* and each *intertie metering point* using *metering data*, *operating results* and *interchange schedule data*. If physical quantities are provided only for each *settlement hour* (as they may be for *interchange schedules*, *non-dispatchable loads*, *self-scheduled generation facilities*, *self-scheduling electricity storage facilities, transitional scheduling*

generators and *intermittent generators*), the *IESO* shall, if necessary for *settlement* purposes, determine the interval amounts defined below by dividing the hourly amounts into twelve equal interval amounts:

$AQEI_{k,h}^{m,t}$ = allocated quantity (in MWh) of *energy* injected by *market participant* 'k' at *primary* or *intertie metering point* 'm' in *metering interval* 't' of *settlement hour* 'h'

$AQEW_{k,h}^{m,t}$ = allocated quantity (in MWh) of *energy* withdrawn by *market participant* 'k' at *primary* or *intertie metering point* 'm' in *metering interval* 't' of *settlement hour* 'h'

$AQOR_{r,k,h}^{m,t}$ = allocated quantity (in MW) of class r reserve for market participant 'k' at primary or intertie metering point 'm' in metering interval 't' of settlement hour 'h'

3.1.10 The *IESO* shall provide the following *capacity auction* information and provide them directly to the *settlement process*:

$CARC_k^m$ = the quantity of *energy* (in MW) of the *hourly demand response resource's demand response contributors* total registered capability for *capacity market participant 'k'* at *delivery point* 'm', as registered with the *IESO* in accordance with the applicable *market manual*;

$CACP^z$ = the *capacity auction clearing price* (in $/MW per day) for the relevant *trading day* in electrical zone 'z'.

$CACP^z_h$ = the *capacity auction clearing price* for *settlement hour* 'h' (in $/MWh) within the *availability window* in electrical zone 'z', determined by taking the *capacity auction clearing price* for the applicable *obligation period* and electrical zone and dividing by the number of *settlement hours* within the *availability window* of the relevant *trading day* within the *obligation period.*

$CAEO^m_{h,k}$ = the quantity of *auction capacity* for *settlement hour* 'h' (in MW) made available by *capacity auction resource* for *capacity market participant* 'k' at *delivery point* or *intertie metering point* 'm' in the relevant *settlement hour* of the *availability window* determined as the lesser of the *resource's energy offers* (in MW) submitted in the day-ahead commitment process, pre-dispatch, and *real-time energy market*, as applicable.

$CARC_k^m$ = the quantity (in MW) of the *hourly demand response resource's demand response contributors* total registered capability for

capacity market participant 'k' at *delivery point* 'm', as registered with the *IESO* in accordance with the applicable *market manual;*

$CBOC^{m}_{k}$ = the buy-out capacity is an amount (in MW) by which the *capacity obligation* for the *obligation period* for *capacity auction resource* for *capacity market participant* 'k' at *delivery point* or *intertie metering point* 'm' is being reduced as per the *capacity market participant's* election pursuant to section 4.7J.3 of Chapter 9.

$CCO^{m}_{k,h}$ = the *capacity obligation* (in MW) for the *obligation period* per *capacity auction resource* for *capacity market participant* 'k' at *delivery point* or *intertie metering point* 'm' in the relevant *settlement hour* 'h', as may be adjusted pursuant to the *market rules*.

$CICAP^{m}_{k}$ = the *cleared ICAP* (in MW) for *capacity auction resource* at *delivery point* or *intertie metering point* 'm' for *capacity market participant* 'k' in the applicable *obligation period*, as determined in accordance with the applicable *market manual*.

$CNPF_{tm}$ = for a given *energy market billing period* 'tm', the non-performance factor as listed in Section 7.1 of Market Manual 12.

$DREBQ^{m}_{k,h}$ = the quantity (in MW) of *auction capacity* made available by an *hourly demand response resource* or *capacity dispatchable load resource* for *capacity market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' of the *availability window*, determined as the lesser of the *resource's energy bids* submitted in the day-ahead commitment process, pre-dispatch, and *real-time energy market*, as applicable, and where such value exceeds the $CARC_{k}^{m}$ for the *resource* in the relevant *energy market billing period*, the $DREBQ^{m}_{k,h}$ shall equal such $CARC_{k}^{m}$.

$DRSQty^{m}_{k,h}$ = the quantity of *energy* (in MW) scheduled for withdrawal in the *real-time market* by *market participant* 'k' at *delivery point* 'm' for an *hourly demand response resource* in *settlement hour* 'h' of the *availability window*, as described in all *real-time schedules* for such *settlement hour*.

$HDRBP^{m}_{k,h}$ = the price component (in $/MWh) of the *energy bid* submitted in the *real time market* for *hourly demand response resource* by *capacity market participant* 'k' at *delivery point* 'm' for *settlement hour* 'h' within the *availability window.*

$HDRDC^{m}_{k,h}$ = the delivered capacity (in MWh) by *hourly demand response resource* for *capacity market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' within the *activation window* of the applicable test activation, calculated as follows:

$$\text{Min}(\text{Curtailed MW}^{m}_{k,h}, \sum_{t=1}^{12}(\frac{\text{Min}(\text{TBQ}^{m}_{k,h}, \text{CARC}_{k^m}, \text{CCO}^{m}_{k,\text{h}})}{12}) - DQSW^{m,t}_{k,h})$$

Where:

(a) "Curtailed $MW^{m}_{k,h}$" is the difference (in MWh) between baseline value, calculated in accordance with the applicable *market manual*, and actual consumption measurement data by *capacity market participant* 'k' at *delivery point* 'm' for an *hourly demand response resource* for *settlement hour* 'h', as calculated in accordance with the applicable *market manual*.

(b) "$TBQ^{m}_{k,h}$" is the offered quantity of *energy* (in MW) contained in the last lamination of the *price quantity pair* of the *energy bid* submitted in the *real time market* by *capacity market participant* 'k' at *delivery point* 'm' for an *hourly demand response resource* in *settlement hour* 'h'.

HDRTAPR = the out of market test activation rate (in $/MWh), as set out in the applicable *market manual.*

$OCMW^{i}_{k}$ = the *over committed capacity* (in MW) of a *generator-backed capacity import resource* for *capacity market participant* 'k' at *intertie metering point* 'i', as determined by the *IESO*.

RAC^{m}_{k} = the available capacity (in MW) of a *capacity auction resource* at *delivery point* or *intertie metering point* 'm' for *capacity market participant* 'k' in the applicable *obligation period*, and is determined in accordance with the following:

(a) For *capacity dispatchable load resources* and *hourly demand response resources*:

$RAC^{m}_{k} = \text{MIN}(DREBQ^{m}_{k,h}, (1.15* CCO^{m}_{k,h}), CICAP^{m}_{k}, CARC_{k}^{m})$

Where:

(i) $CARC_k^m$ is only applicable to *virtual hourly demand response resources*

(b) For *capacity generation resources*, *system-backed capacity import resources*, *generator-backed capacity import resources* and *capacity storage resources*:

$RAC^m_k = MIN(CAEO^m_{h,k}, (1.15* CCO^m_{k,h}), CICAP^m_k)$

3.1.11 The *IESO* shall, in accordance with the applicable *market manual,* determine the required *settlement* data for *registered market participants* that submitted *dispatch data* for *facilities* operating as *pseudo-units,* using the information submitted under Chapter 7, sections 2.2.6G and 2.2.6J, and shall provide this *settlement* data directly to the *settlement process*.

3.2 [Intentionally left blank – section deleted]

3.2.1 [Intentionally left blank – section deleted]

3.3 Hourly Settlement Amounts in the Real-Time Energy Market

3.3.1 The hourly net *energy market settlement* credit for *market participant* 'k' in *settlement hour* 'h' ("$NEMSC_{k,h}$") shall be determined by the appropriate equations set forth in section 3.3.2 and where applicable, in accordance with section 2.1.2 of Chapter 8.

3.3.2 For *market participant* 'k', $NEMSC_{k,h}$ shall be the sum, over all *metering intervals* 't' in *settlement hour* 'h' and all *RWMs* and *intertie metering points*, of the *settlement amounts* determined for each *metering interval* and *RWMs* or *intertie metering point*, as follows:

3.3.2.1 in respect of a *dispatchable facility* or an *intertie metering point* associated with:

- an injecting boundary entity;
- a withdrawing *boundary entity* where the associated *intertie congestion price* is less than zero; or,
- a withdrawing *boundary entity* conducting a wheeling through transaction that is linked as per Chapter 7 section 3.5.8.2:

$$NEMSC_{k,h} = \Sigma_{t,m} (EMP_h^{m,t} \times ((AQEI_{k,h}^{m,t} - AQEW_{k,h}^{m,t}) + \Sigma_{s,b} (BCQ_{s,k,h}^{m,t} - BCQ_{k,b,h}^{m,t})))$$

where:

t = all *metering intervals* in *settlement hour* 'h'

m = all *RWMs* relating to a *dispatchable facility* and all *intertie metering points* associated with: i) any injecting *boundary entities*; ii) any withdrawing *boundary entities* where the associated *intertie congestion price* is less than zero; and, iii) any withdrawing *boundary entity* conducting a wheeling through transaction that is linked as per Chapter 7 section 3.5.8.2

s = all *selling market participants*

b= all *buying market participants*

and

3.3.2.1A in respect of an *intertie metering point* associated with a withdrawing *boundary entity* where that *intertie congestion price* is not less than zero:

$$NEMSC_{k,h} = \Sigma_{t,m} ((MAX (x_h^{m,t}, EMP_h^{m,t})) \times AQEW_{k,h}^{m,t})$$

where:

t = all *metering intervals* in *settlement hour* 'h'

m = all *intertie metering points* where the *intertie congestion price* is not less than zero

and

3.3.2.2 in respect of a *non-dispatchable load facility*, *a self-scheduling generation facility*, a *self-scheduling electricity storage facility*, a *transitional scheduling generator* or *intermittent generator*.

$$NEMSC_{k,h} = HOEP_h \times \Sigma_{t,m} (AQEI_{k,h}^{m,t} - AQEW_{k,h}^{m,t} + \Sigma_s BCQ_{s,k,h}^{m,t}) - \Sigma_{n,b,t} (EMP_h^{n,t} \times BCQ_{k,b,h}^{n,t})$$

where:

m = all *RWMs* relating to a *non-dispatchable load facility,* a *self-scheduling generation facility,* a *self-scheduling electricity storage facility,* a *transitional scheduling generator* or *intermittent generator*

n = all *RWMs* and *intertie metering point*s

s = all *selling market participant*s

b= all *buying market participants*

t = all *metering interval*s in *settlement hour* 'h'

3.3.3 [Intentionally left blank]

3.4 Hourly Settlement Amounts for Operating Reserve and Charges

3.4.1 The hourly *operating reserve settlement* credit for *market participant* 'k' in *settlement hour* 'h' ("$ORSC_{k,h}$") shall be determined by the following equation:

$$ORSC_{k,h} = \sum_{m,t,r} PROR_{r,h}^{m,t} \times AQOR_{r,k,h}^{m,t}$$

where:
m = all *primary RWMs* and *intertie metering points*
t = all *metering intervals* in *settlement hour* 'h'
r1 = 10-minute spinning *operating reserve*
r2 = 10-minute non-spinning *operating reserve;* and
r3 = 30-minute *operating reserve*.

3.4.2 The *IESO* shall apply the non-accessibility charge specified in section 7.4.2.1 of Chapter 7, and a *market participant* shall be subject to such non-accessibility charge, for every *dispatch interval* where the *market participant* is scheduled to provide *operating reserve* but was not dispatched to increase *energy generation* or reduce energy withdrawal pursuant to section 7.4.3 Chapter 7, and where the total scheduled *operating reserve* is greater than the total accessible *operating reserve* as determined by:

$$\sum_R AQOR_{rn,k,h}^{m,t} > TAOR_{k,h}^{m,t} \text{ and } \sum_R AQOR_{rn,k,h}^{m,t} > 0$$

Where:

R: is the set of all classes of *operating reserve*

For *operating reserve* provided by a *dispatchable load*:

$$TAOR_{k,h}^{m,t}=Max\left(0,AQEW_{k,h}^{m,t}-MC_{m}^{h,t}\right)$$

$MC_m^{h,t}$ = minimum consumption level and is equal to the quantity in the *price-quantity pair* where the *bid* price is *MMCP*

For *operating reserve* provided by a *generator* other than aggregated *facilities*:

$$TAOR_{k,h}^{m,t}=Max\left(0,MAX_CAP_{k,h}^{m,t}-AQEI_{k,h}^{m,t}\right)$$

$MAX_CAP_{k,h}^{m,t}$ = the maximum limit used in determining the *real-time schedule* in the *dispatch* scheduling and pricing process as described in Chapter 7, Appendix 7.5 for each *dispatch interval*

3.4.2.1 Where *operating reserve* is scheduled to be provided by aggregated *facilities,* a *market participant* shall be subject to a non-accessibility charge for every *dispatch interval* where the *market participant* is scheduled to provide *operating reserve* but was not dispatched to increase *energy generation* pursuant to section 7.4.3 of Chapter 7, and where the total scheduled *operating reserve* is greater than the total accessible *operating reserve* as determined by:

$$\sum_R^M AQOR_{rn,k,h}^{m,t} > TAOR_CA_{k,h}^{M,t}, \text{ and } \sum_R^M AQOR_{rn,k,h}^{m,t} > 0$$

Where:

R: is the set of all classes of *operating reserve*

M: is set of all *delivery points* 'm' that are compliance aggregated

Total accessible *operating reserve* (TAOR) for aggregated *generators:*

$$TAOR_CA_{k,h}^{M,t}=Max\left(0,\sum^{M}\left(MAX_CAP_{k,h}^{m,t}-AQEI_{k,h}^{m,t}\right)\right)$$

$MAX_CAP_{k,h}^{m,t}$= the maximum limit used in determining the *real-time schedule* in the *dispatch* scheduling and pricing process as described in Chapter 7, Appendix 7.5 for each *dispatch interval*

3.4.3 Where it is determined that a non-accessibility charge is to be applied to a *market participant* pursuant to section 3.4.2, the non-accessibility charge shall be calculated for each class of *operating reserve* as follows:

For synchronized *ten-minute operating reserve*:

$$ORSCB_{r1,k,h}^{m,t}=Min\left(0,\left(TAOR_{k,h}^{m,t}-AQOR_{r1,k,h}^{m,t}\right)\times PROR_{r1,h}^{m,t}\right)$$

For non-synchronized *ten-minute operating reserve*:

$$ORSCB_{r2,k,h}^{m,t}=Min\left(0,\left(Max\left(0,TAOR_{k,h}^{m,t}-AQOR_{r1,k,h}^{m,t}\right)-AQOR_{r2,k,h}^{m,t}\right)\times PROR_{r2,h}^{m,t}\right)$$

For *thirty-minute operating reserve*:

$$ORSCB_{r3,k,h}^{m,t}=Min\left(0,\left(Max\left(0,TAOR_{k,h}^{m,t}-AQOR_{r1,k,h}^{m,t}-AQOR_{r2,k,h}^{m,t}\right)-AQOR_{r3,k,h}^{m,t}\right)\times PROR_{r3,h}^{m,t}\right)$$

Where:

$AQOR_{rn,k,h}^{m,t}$: Allocated quantity in MW of *class r reserve* for *market participant* 'k' at *RWM* 'm' in *metering interval* 't' of *settlement hour* 'h';

$PROR_{rn,h}^{m,t}$*: Market price* in $/MW of *class r reserve* in *metering interval* 't' of *settlement hour* 'h' at *RWM* 'm';

r1 denotes the *ten-minute operating reserve* that is synchronized with the *IESO-controlled grid*;

r2 denotes *ten-minute operating reserve* that is not synchronized with the *IESO-controlled grid*; and

r3 denotes *thirty-minute operating reserve*.

3.4.3.1 Where it is determined that a non-accessibility charge is to be applied to a *market participant* pursuant to section 3.4.2.1, the amount of non-

accessible *operating reserve* shall be determined for each class of *operating reserve* as follows:

For aggregated *generators* scheduled to provide synchronized *ten-minute operating reserve*:

$$\mathrm{ORIA_CA}^{\mathrm{M,t}}_{\mathrm{r1,k,h}} = \mathrm{Min}\left(0, \mathrm{TAOR_CA}^{\mathrm{M,t}}_{\mathrm{k,h}} - \sum^{\mathrm{M}} \mathrm{AQOR}^{\mathrm{m,t}}_{\mathrm{r1,k,h}}\right)$$

For aggregated *generators* scheduled to provide non-synchronized *ten-minute operating reserve*:

$$ORIA_CA^{M,t}_{r2,k,h} = Min\left(0, Max\left(0, TAOR_CA^{M,t}_{k,h} - \sum^{M} AQOR^{m,t}_{r1,k,h}\right) - \sum^{M} AQOR^{m,t}_{r2,k,h}\right)$$

For aggregated *generators* scheduled to provide *thirty-minute operating reserve*:

$$ORIA_CA^{M,t}_{r3,k,h} = Min\left(0, Max\left(0, TAOR_CA^{M,t}_{k,h} - \sum^{M} AQOR^{m,t}_{r1,k,h} - \sum^{M} AQOR^{m,t}_{r2,k,h}\right) - \sum^{M} AQOR^{m,t}_{r3,k,h}\right)$$

Where:

$AQOR^{m,t}_{rn,k,h}$: Allocated quantity in MW of *class r reserve* for *market participant* ‘k’ at *RWM* ‘m’ in *metering interval* ‘t’ of *settlement hour* ‘h’;

r1 denotes the *ten-minute operating reserve* that is synchronized with the *IESO-controlled grid*;

r2 denotes *ten-minute operating reserve* that is not synchronized with the *IESO-controlled grid*; and

r3 denotes *thirty-minute operating reserve*.

3.4.3.2 The non-accessibility charge calculated pursuant to section 3.4.2.1 will be divided among individual aggregate *facilities* on a pro-rated based on the

percentage of total inaccessible *operating reserve* attributed to it as determined as follows:

$$ORCF^{m,t}_{rn,k,h} = \frac{ORIA^{m,t}_{rn,k,h}}{\sum^{M1} ORIA^{m,t}_{rn,k,h}}$$

M1: is the set of delivery point 'm' where a resource has operating reserve scheduled for OR class 'rn'.

For synchronized *ten-minute operating reserve*:

$$ORIA^{m,t}_{r1,k,h} = Min\left(0,\left(TAOR^{m,t}_{k,h} - AQOR^{m,t}_{r1,k,h}\right)\right)$$

For non-synchronized *ten-minute operating reserve*:

$$ORIA^{m,t}_{r2,k,h} = Min\left(0,\left(Max\left(0,TAOR^{m,t}_{k,h} - AQOR^{m,t}_{r1,k,h}\right) - AQOR^{m,t}_{r2,k,h}\right)\right)$$

For *thirty-minute operating reserve*:

$$ORIA^{m,t}_{r3,k,h} = Min\left(0,\left(Max\left(0,TAOR^{m,t}_{k,h} - AQOR^{m,t}_{r1,k,h} - AQOR^{m,t}_{r2,k,h}\right) - AQOR^{m,t}_{r3,k,h}\right)\right)$$

Where:

Total inaccessible *operating reserve* for *generators:*

$$ORIA^{m,t}_{rn,k,h} = Min\left(0, TAOR^{m,t}_{k,h} - \sum_{R} AQOR^{m,t}_{rn,k,h}\right)$$

Total accessible *operating reserve* for *generators*:

$$TAOR^{m,t}_{k,h} = Max\left(0, MAX_CAP^{m,t}_{k,h} - AQEI^{m,t}_{k,h}\right)$$

3.4.3.3 The non-accessibility charge calculated pursuant to section 3.4.3.2 will be calculated for an individual aggregate *facility* as follows:

$$ORSCB^{m,t}_{rn,k,h} = ORIA_CA^{M,t}_{rn,k,h} \times ORCF^{m,t}_{rn,k,h} \times PROR^{m,t}_{rn,h}$$

Where:

$PROR_{rn,h}^{m,t}$: *Market price* in $/MW of *class r reserve* in *metering interval* 't' of *settlement hour* 'h' at *RWM* 'm'.

3.5 Hourly Settlement Amounts for Congestion Management

3.5.1 The *dispatch instructions* provided by the *IESO* to *market participant* 'k' will sometimes instruct k to deviate from its *market schedule* in ways that, based on *market participant* 'k's *offers* and *bids*, imply a change to *market participant* 'k's net operating profits relative to the operating profits implied by *market participant* 'k's *market schedule*. When this occurs and *market participant* 'k' responds to the *IESO*'s *dispatch instructions*, *market participant* 'k' shall, subject to Appendix 7.6 of Chapter 7, receive as compensation a *settlement* credit equal to the change in implied operating profits resulting from such response, calculated in accordance with section 3.5.2. If *market participant* 'k' does not fully or accurately respond to its *dispatch instructions* from the *IESO*, the compensation paid to *market participant* 'k' shall be altered as set forth in this section 3.5, or as otherwise specified by the *IESO*.

3.5.1A A *registered market participant* for a *registered facility* that is a *dispatchable load* or an *electricity storage facility* withdrawing *energy* is not entitled to a congestion management *settlement* credit determined in accordance with section 3.5.2 where that *registered facility's* DQSW is less than the corresponding MQSW at that location for the same *metering interval* as the result of that *registered facility's* own equipment or operational limitations, if:

3.5.1A.1 that *registered facility* does not fully or accurately respond to its *dispatch instructions*; or

3.5.1A.2 the ramping capability of that *registered facility*, as represented by the ramp rate set out in the *offers* or *bids,* is below the threshold for the *IESO* to modify *dispatch instructions* and thereby prevents changes to the *dispatch*;

and then the *IESO* may withhold or recover such congestion management *settlement* credits and shall redistribute any recovered payments in accordance with section 4.8.2 of Chapter 9.

3.5.1B A *market participant* shall not be *invoiced* congestion management *settlement* credits for an export transaction if that transaction attracted the congestion management *settlement* credits under the following conditions:

3.5.1B.1 the net *interchange schedule* limit is binding in the *market schedule* on an economic export transaction in pre-dispatch, and subsequently, in accordance with section 6.1.3 of Chapter 7, the *IESO* increases the quantity of that transaction in the *real-time schedule*; or

3.5.1B.2 the net *interchange schedule* limit is binding in the *market schedule* on an uneconomic export transaction in pre-dispatch, and subsequently, in accordance with section 6.1.3 of Chapter 7, the *IESO* decreases the quantity of that transaction in the *real-time schedule*.

The amount of congestion management *settlement* credits referred to in this section is limited to the portion of the transaction that is modified by the *IESO*.

3.5.1C [Intentionally left blank – section deleted]

3.5.1D A *registered market participant* for a *registered facility* that is a *dispatchable load* or an *electricity storage facility* withdrawing energy, shall not be entitled to a congestion management *settlement* credit determined in accordance with section 3.5.2 for *settlement hour* 'h' where:

3.5.1D.1 the *price-quantity pairs* contained in the *energy bid* associated with that *registered facility* for *settlement hour* 'h' are not identical to the *price-quantity pairs* in the *energy bid* associated with the same *registered facility* for the applicable preceding *settlement hour* or following *settlement hour*;

3.5.1D.2 the change in *energy bid* as referred to in section 3.5.1D.1 results in a change in the quantity scheduled in the *market schedule* for that *registered facility* as described in the applicable *market manual*;

3.5.1D.3 the change in *energy bid* as referred to in section 3.5.1D.1 results in the ramping of the that *registered facility* as described in the applicable *market manual*; and

3.5.1D.4 that *registered facility's* DQSW is less than the corresponding MQSW at that locaton for any *metering interval* falling within *settlement hour* 'h'.

3.5.1E For the purpose of calculating congestion management *settlement* credits for *variable generators* that are *registered market participants*:

3.5.1E.1 if the *registered facility* is required to follow *dispatch instructions* issued by the *IESO* for any given *dispatch intervals,* the corresponding congestion management *settlement* credits for those *dispatch intervals* shall be calculated using the *market schedule* quantity determined in accordance with section 6.4.2.9A of Chapter 7; and

3.5.1E.2 except as noted in section 3.5.1F, the *market participant* shall not be eligible for congestion management *settlement* credits in *dispatch intervals* where the *registered facility* is issued a *release notification* by the *IESO* in accordance with section 7.1, which remains in effect for any *dispatch interval*.

3.5.1F For the purpose of calculating congestion management *settlement* credits for *variable generators* that are *registered market participants,* if the *registered facility* is subject to a *release notification* for a given *dispatch interval*, and for that *dispatch interval* the *registered facility's* $MQSI_{k,h}^{m,t}$ is less than the corresponding $DQSI_{k,h}^{m,t}$ for the same *dispatch interval* as a result of the *market participant's energy offers* being partially or fully uneconomic in the unconstrained schedule relative to the constrained schedule, the congestion management *settlement* credits for that *dispatch interval* shall be calculated pursuant to section 3.5.2A using the difference between the operating profit based on the *market schedule* quantity $MQSI_{k,h}^{m,t}$ determined in accordance with section 6.4.2.9B of Chapter 7 and the operating profit calculated based on the allocated quantity of *energy* injected (AQEI) for the same *dispatch interval*.

3.5.1G A *registered market participant* for a *registered facility* that is a *dispatchable generation facility* or an *electricity storage facility* injecting *energy*, shall not be entitled to a congestion management *settlement* credit determined in accordance with section 3.5.2 for any *dispatch interval 't'* within *settlement hour* 'h' where:

3.5.1G.1 the registered facility is not a quick-start facility;

3.5.1G.2 the *IESO* has identified the *dispatch interval* as part of consecutive

ramp-down *dispatch intervals* resulting in the shutdown of the *registered facility,* including those where the *registered facility* does not fully or accurately respond to its *dispatch instructions*, in accordance with the applicable *market manual*; and

3.5.1G.3 the *registered facility's* $MQSI_{k,h}^{m,t}$ is less than the corresponding

$DQSI_{k,h}^{m,t}$ for the same *dispatch interval*.

A *registered facility* subject to the withholding or recovery of a congestion management *settlement* credit for a *dispatch interval* under this section shall receive a ramp-down *settlement* amount for the applicable *dispatch interval* in accordance with section 3.5A.

3.5.2 Subject to sections 3.5.1A, 3.5.1D, 3.5.1E, 3.5.1F, 3.5.1G, 3.5.6, 3.5.6A, 3.5.6B, 3.5.6C, 3.5.6D, 3.5.6F, 3.5.6G, 3.5.9, 3.5.10 and 3.5.11 and subject to Appendix

7.6 of Chapter 7, the hourly congestion management *settlement* credit for *market participant* 'k' for *settlement hour* 'h' ("$CMSC_{k,h}$") shall be determined by the following equation:

Let 'BE' be a matrix of n *price-quantity pairs* offered by *market participant* 'k' to supply *energy* during *settlement hour* 'h'

Let 'BR_r' be a matrix of n *price-quantity pairs* offered by *market participant* 'k' to supply class r *operating reserve* during *settlement hour* 'h'

Let 'BL' be a matrix of n *price-quantity pairs* bid by *market participant* 'k' to withdraw *energy* by a *dispatchable load* or an *electricity storage facility* during *settlement hour* 'h'

Let OP(P,Q,B) be a profit function of Price (P), Quantity (Q) and an n x 2 matrix (B) of offered *price-quantity pairs*:

$$OP(P,Q,B) = P \cdot Q - \sum_{i=1}^{s^*} P_i \cdot (Q_i - Q_{i-1}) - (Q - Q_{s^*}) \cdot P_{s^*+1}$$

Where:
s^* is the highest indexed row of B such that $Q_{s^*} \leq Q \leq Q_n$ and where, $Q_0=0$
B is matrix BE, BR_r, or BL (see above)

Using the terms below, let CMSC be expressed as follows:

$$CMSC_{k,h} = OPE_{k,h} + OPR_{k,h} + OPL_{k,h}$$

Where:

$OPE_{k,h}$ represents that component of the congestion management *settlement* credit for *market participant* 'k' during *settlement hour* 'h' attributable to a constraint on *energy* production subject to section 3.5.1 and is calculated as follows:

$$OPE_{k,h} = \sum_{m,t} \left[\begin{array}{l} OP(EMP_h^{m,t}, MQSI_{k,h}^{m,t}, BE) - \\ MAX\left(OP(EMP_h^{m,t}, DQSI_{k,h}^{m,t}, BE), OP(EMP_h^{m,t}, AQEI_{k,h}^{m,t}, BE)\right) \end{array} \right]$$

Where:

MAX[X,Y] = Maximum of X or Y

During any *metering interval* 't' within *settlement hour* 'h' in which the mathematical sign of $DQSI_{k,h}^{m,t} - MQSI_{k,h}^{m,t}$ is not equal to the mathematical sign

of $AQEI_{k,h}^{m,t} - MQSI_{k,h}^{m,t}$, the component of $OPE_{k,h}$ at location m, determined in accordance with section 3.1.4A, or *intertie metering point* 'm' for that *metering interval* 't' shall equal zero.

$OPR_{k,h}$ represents that component of the congestion management *settlement* credit for *market participant* 'k' during *settlement hour* 'h' attributable to a constraint on the provision of *operating reserve* subject to section 3.5.1 and is calculated as follows:

$$OPR_{k,h} = \sum_{m,t,r}\left[\begin{array}{l} OP(PROR_{r,h}^{m,t}, SQROR_{r,k,h}^{m,t}, BR_r) - \\ MAX\left(OP(PROR_{r,h}^{m,t}, DQSR_{r,k,h}^{m,t}, BR_r), OP(PROR_{r,h}^{m,t}, AQOR_{r,k,h}^{m,t}, BR_r)\right) \end{array}\right]$$

During any *metering interval* 't' within *settlement hour* 'h' in which the mathematical sign of $DQSR_{r,k,h}^{m,t} - SQROR_{r,k,h}^{m,t}$ is not equal to the mathematical sign of $AQOR_{r,k,h}^{m,t} - SQROR_{r,k,h}^{m,t}$, the component of $OPR_{k,h}$ at location m, determined in accordance with section 3.1.4A, or *intertie metering point* 'm' for that *metering interval* 't' shall equal zero.

$OPL_{k,h}$ represents that component of the congestion management *settlement* credit for *market participant* 'k' during *settlement hour* 'h' attributable to a constraint on the withdrawal of *energy* by a *dispatchable load* or an *electricity storage facility* subject to section 3.5.1. $OPL_{k,h}$ utilizes the negative of each output from each component Operating Profit (OP) function so as to correct for negative revenue streams (owing to withdrawals of *energy*).

$OPL_{k,h}$ is calculated as follows:

$$OPL_{k,h} = \sum_{m,t}\left[\begin{array}{l} -1 \times OP(EMP_h^{m,t}, MQSW_{k,h}^{m,t}, BL) - \\ MAX\left(-1 \times OP(EMP_h^{m,t}, DQSW_{k,h}^{m,t}, BL), -1 \times OP(EMP_h^{m,t}, AQEW_{k,h}^{m,t}, BL)\right) \end{array}\right]$$

During any *metering interval* 't' within *settlement hour* 'h' in which the mathematical sign of $DQSW_{k,h}^{m,t} - MQSW_{k,h}^{m,t}$ is not equal to the mathematical sign of $AQEW_{k,h}^{m,t} - MQSW_{k,h}^{m,t}$, the component of $OPL_{k,h}$ at location m, determined in accordance with section 3.1.4A, or *intertie metering point* 'm' for that *metering interval* 't' shall equal zero.

3.5.2A For purposes of section 3.5.1F, for *variable generators* that are *registered market participants*, the $OPE_{k,h}$ equation in section 3.5.2 shall be calculated as follows:

$$OPE_{k,h} = \sum_{m,t}\left[OP(EMP_h^{m,t}, MQSI_{k,h}^{m,t}, BE) - OP(EMP_h^{m,t}, AQEI_{k,h}^{m,t}, BE)\right]$$

3.5.3 [Intentionally left blank]

3.5.4 Subject to section 5.3.4 of Chapter 5, during instances where $CMSC_{k,h}$ is calculated at an *intertie metering point* at which a *market participant* is conducting an import or export transaction for a *physical service* that is subject to a *constrained off event* that is reflected in *dispatch instructions* issued by the *IESO* as a result of a request initiated by an entity other than the *IESO*, the *IESO* shall not calculate any portion of $CMSC_{k,h}$ pertaining to the affected transaction for those *metering intervals* within *settlement hour* 'h' in which such conditions exist, and for greater certainty, during any *metering interval* in which:

3.5.4.1 $MQSI_{k,h}^{m,t}$ is not equal to $DQSI_{k,h}^{m,t}$ as a result of such a *constrained off event*;

3.5.4.2 $MQSW_{k,h}^{m,t}$ is not equal to $DQSW_{k,h}^{m,t}$ as a result of such a *constrained off event*; or

3.5.4.3 $SQROR_{r,k,h}^{m,t}$ is not equal to $DQSR_{r,k,h}^{m,t}$ as a result of such a *constrained off event*;

and irrespective of whether or not a *constrained on event* or a *constrained off event* was affecting the transaction in any preceding *metering interval*.

3.5.5 A DQSI, DQSW or DQSR, quantity as the case may be, that departs from its corresponding *market schedule* quantity due to the circumstances described in section 3.5.4 shall be denoted as such within the supporting data provided to the affected *market participant* as part of the content of *settlement statements* described in sections 6.5.4.1 and 6.5.4.3.

3.5.6 The *IESO* shall adjust, in the matrices specified in section 3.5.2 and for the purposes of determining the applicable congestion management *settlement* credit payments, any *offer price* that:

3.5.6.1 is associated with a *generation facility,* an injecting *electricity storage facility,* or is associated with an injecting *boundary entity*; and

3.5.6.2 is less than a specified lower limit where such limit is the lesser of 0.00 $/MWh and the *energy market price* for the applicable *dispatch interval*;

to that lower limit.

3.5.6A The *IESO* may adjust, in the matrices specified in section 3.5.2 and for the purposes of determining the applicable congestion management *settlement* credit payments, any *bid* price that:

3.5.6A.1 is associated with a *dispatchable load facility* or is associated with a withdrawing *boundary entity* or a withdrawing *electricity storage facility*;

3.5.6A.2 is less than the prices determined by the *IESO* in accordance with the applicable *market manual*; and

3.5.6A.3 is less than the *energy market price* in the applicable Ontario or *intertie zone* for the applicable *dispatch interval*;

to the lesser of the prices determined by the *IESO* in accordance with the applicable *market manual* and the *energy market price* in the applicable Ontario or *intertie zone*.

3.5.6B A *registered market participant* for a *registered facility* that is a *dispatchable generation facility*, who:

- increases the *offer* price associated with the *generation facility minimum loading point* for its *minimum generation block run-time* so that under Chapter 7 section 5.7.1.4 the *registered market participant* for the *generation facility* is no longer eligible for the applicable guarantee; and
- has received a manual constraint from the *IESO* for the *generation facility* under Chapter 7 section 6.3A.2 or 6.3A.4;

subject to section 3.5.6E, is not entitled to any inappropriate congestion management *settlement* credit or ramp-down *settlement* amount, determined in accordance with section 3.5.2 or 3.5A respectively, associated with that *offer* price increase for *settlement hour* 'h', where *settlement hour* 'h' falls within the *generation facility minimum generation block run-time*. The *IESO* may recover such congestion management *settlement* credit or ramp-down *settlement* amount in accordance with section 3.5.6E.

3.5.6C A *registered market participant* for a *registered facility* that is a dispatchable *generation facility* or a dispatchable *electricity storage facility* that can inject who, for *settlement hour* 'h':

- is unable to comply with a *dispatch instruction* under section7.5.3 of Chapter 7, to prevent endangering the safety of any person, equipment damage, or violation of any *applicable law*; and/or
- requests that the *IESO* apply a constraint to the *dispatchable generation facility or the dispatchable electricity storage facility that can inject* to prevent endangering the safety of any person, equipment damage, or violation

of any *applicable law*, excluding constraints applied under Chapter 7 sections 6.3A.2 or 6.3A.4;

subject to section 3.5.6E, is not entitled to any inappropriate congestion management *settlement* credit or ramp-down *settlement* amount, determined in accordance with section 3.5.2 or 3.5A respectively, resulting from the above actions for *settlement hour* 'h'. The *IESO* may recover such congestion management *settlement* credit or ramp-down *settlement* amount in accordance with section 3.5.6E.

3.5.6D A *registered market participant* for a *registered facility* that is a *dispatchable generation facility* and is fuelled by a related *generation facility*, who, for *settlement hour* 'h':

- has received a constraint from the *IESO* for the *dispatchable generation facility* as per the applicable *market manual*; and
- submits or has submitted an *offer* price for that *dispatchable generation facility* for *settlement hour* 'h' greater than a specified limit defined in the applicable *market manual*;

subject to section 3.5.6E, is not entitled to any inappropriate congestion management *settlement* credit or ramp-down *settlement* amount, determined in accordance with section 3.5.2 or 3.5A respectively, associated with that *offer* price for *settlement hour* 'h'. The *IESO* may recover such congestion management *settlement* credit or ramp-down *settlement* amount in accordance with section 3.5.6E.

3.5.6E The *IESO* may recover congestion management *settlement* credits or ramp-down *settlement* amounts in accordance with sections 3.5.6B, 3.5.6C, 3.5.6D, 3.5.6G and Section 21.5 of Chapter 7. In this situation, the *IESO* shall:

- notify the *market participant* of its intent to recover that *congestion management settlement credit* or ramp-down *settlement amount*; and
- notify the *market participant* of the time, which shall not be less than five *business days* from the date of receipt of the notice, within which the *market participant* may make written representations in response to the *IESO's* intent.

On receiving a response from the *market participant* within the specified time period, or upon expiry of the specified time period within which no response is received from the *market participant*, the *IESO* shall either:

- determine the amount of the congestion management *settlement* credit or ramp-down *settlement* amount to recover and notify the *market participant* accordingly; or

- gather further information as the *IESO* determines appropriate to determine the amount of the congestion management *settlement* credit or ramp-down *settlement* amount to recover and notify the *market participant* accordingly of the determination.

The *IESO* shall redistribute any payments that are recovered in accordance with section 4.8.2.

3.5.6F Where the *energy market price* for the applicable *dispatch interval* is less than zero, the *IESO* may adjust, in the matrices specified in section 3.5.2 and for the purposes of determining the applicable congestion management *settlement* credit payments, any *bid* price that:

3.5.6F.1 is associated with a withdrawing *boundary entity* at an *intertie* that is not import congested; and

3.5.6F.2 is greater than the *energy market price* in the applicable *intertie zone* for the applicable *dispatch interval;*

to the prices determined by the *IESO* in accordance with the applicable *market manual*.

3.5.6G A *registered market participant* for a *registered facility* that is a *dispatchable load*, or a dispatchable *electricity storage facility* that can withdraw, who, for *settlement hour* 'h':

- is unable to comply with a *dispatch instruction* under section 7.5.3 of Chapter 7, to prevent endangering the safety of any person, equipment damage, or violation of any *applicable law*; and/or

- requests that the *IESO* apply a constraint to the *dispatchable load facility* or the dispatchable *electricity storage facility* that can withdraw to prevent endangering the safety of any person, equipment damage, or violation of any *applicable law;*

subject to section 3.5.6E, is not entitled to any inappropriate congestion management *settlement* credit, determined in accordance with section 3.5.2, resulting from the above actions for *settlement hour* 'h'. The *IESO* may recover such congestion management *settlement* credit in accordance with section 3.5.6E.

3.5.7 [Intentionally left blank – section deleted]

3.5.7A A *registered market participant* for a *constrained on generation unit* is not entitled to a congestion management *settlement* credits determined in accordance with section 3.5.2 for that *facility* up to *minimum loading point* if the congestion management *settlement* credit is earned as a result of constraints applied under Chapter 7, section 5.8.5 for hours in the day after the *dispatch day*. In this case, the *IESO* may withhold or recover such congestion management *settlement* credits and shall redistribute any recovered payments in accordance with section 4.8.2 of Chapter 9.

3.5.8 Notwithstanding any other provision in the *market rules*, a *market participant* shall not be eligible for any congestion management *settlement* credit payments for a wheeling through transaction where the *market participant* effects the transaction by linking an *energy offer* and *energy bid* under section 3.5.8.2 of Chapter 7.

3.5.9 The *IESO* may limit, withhold or recover any congestion management *settlement* credits or ramp-down *settlement* amounts that result from the acceptance by the *IESO* of the replacement *energy* referred to in section 3.3.4C of Chapter 7 and shall redistribute any recovered payments in accordance with section 4.8.2. Any applicable congestion management *settlement* credits or ramp-down *settlement* amounts for replacement *energy* accepted by the *IESO* shall be limited as set out in the applicable *market manual* to an *IESO* estimate of what would have been received by the original *facility* had it not experienced the *forced outage.*

3.5.10 In accordance with the applicable *market manual*, a *market participant* shall not be entitled to any congestion management *settlement* credits determined in accordance with section 3.5.2 and attributable to a *constrained off event* associated with an *energy* offer or an *energy* bid from a *boundary entity* for an injection into or withdrawal from the *IESO-controlled grid,* where the *constrained off event* appears in the *pre-dispatch schedule* identified in section 6.1.3 of Chapter 7. In this case, the *IESO* may withhold or recover such congestion management *settlement* credits and shall redistribute any recovered payments in accordance with section 4.8.2.

3.5.11 A *market participant* shall not be eligible for any congestion management *settlement* credit payments in respect of an *energy* bid from a *boundary entity* for a *called capacity export*. The *IESO* may withhold or recover any congestion management *settlement* credits paid in respect of *called capacity exports* and shall redistribute any recovered payments in accordance with section 4.8.2.

3.5A Hourly Settlement Amounts for Ramp-Down

3.5A.1 Subject to section 3.5A.2, the ramp-down *settlement* amount for any *dispatch interval* 't' identified in section 3.5.1G for market *participant* 'k' within *settlement hour* 'h'("$RDSA_{k,h}$") shall be the lesser of:

- the congestion management *settlement* credit for *dispatch interval* 't' which was withheld or recovered under section 3.5.1G; and
- the ramp-down compensation ("$RDC_{k,h}^{m,t}$") as determined by the following equation:

Let 'BE' be a matrix of n *price-quantity pairs* offered by *market participant* 'k' to supply *energy* during the *settlement hour* immediately before the hour in which ramp-down begins, adjusted by a factor as specified in the applicable *market manual*.

Let OP(P,Q,B) be a function of Price (P), Quantity (Q) and an n x 2 matrix (B) of offered *price-quantity pairs*:

$$OP(P,Q,B) = P \cdot Q - \sum_{i=1}^{s^*} P_i \cdot (Q_i - Q_{i-1}) - (Q - Q_{s^*}) \cdot P_{s^*+1}$$

Where:
s^* is the highest indexed row of BE such that $Q_{s^*} \leq Q \leq Q_n$ and where, $Q_0=0$

Using the terms below, let $RDC_{k,h}^{m,t}$ be expressed as follows:

$$RDC_{k,h}m,t = MAX\left[0, \left[\begin{array}{l} OP(EMP_h^{m,t}, MQSI_{k,h}^{m,t}, BE) - \\ MAX\left(OP(EMP_h^{m,t}, DQSI_{k,h}^{m,t}, BE), OP(EMP_h^{m,t}, AQEI_{k,h}^{m,t}, BE)\right) \end{array}\right]\right]$$

3.5A.2 The *IESO* may recover the hourly ramp-down *settlement* amount determined in accordance with section 3.5A.1 pursuant to sections 3.5.6B, 3.5.6C, 3.5.6D and 3.5.6E, as applicable.

3.6 Hourly Settlement Amounts for Transmission Rights and Charges

3.6.1 The *TR settlement* credit for *market participant* 'k' in *settlement hour* 'h' ("$TRSC_{k,h}$") shall, other than where section 4.4.2.2 of Chapter 8 applies, be determined by the following equation:

$$TRSC_{k,h} = \max[0, \sum_{j,i} (1/12) \times QTR_{k,h}^{i,j} \times \sum_{t} (EMP_h^{j,t} - EMP_h^{i,t})]$$

where:

j = all *primary RWM's* and *intertie metering points*

i = all *primary RWM's* and *intertie metering points*

3.6.2 The contribution to the *transmission charge reduction fund* in *settlement hour* 'h' ("$TCRF_h$") shall be the net congestion rentals collected by the *IESO* (the negative of the net *energy market settlement* credit paid to *market participants*) less the net payments from the *IESO* to *market participants* under *TRs*, or:

$$TCRF_h = \sum_{t,m} (EMP_h^{m,t} - EMP_h^{REF,t}) \times \sum_{k} (AQEW_{k,h}^{m,t} - AQEI_{k,h}^{m,t}) - \sum_{k} TRSC_{k,h}$$

where:

t = all *metering intervals* in *settlement hour* 'h'

m = all *primary* RWMs and *intertie metering points*

k = all *market participants*

$EMP_h^{REF,t}$ = *energy market price* at the reference bus in metering interval 't' of *settlement hour* 'h'. Until such time that locational pricing is implemented in the *IESO-administered markets*, the uniform *energy market price* is the *energy market price* at the reference bus.

3.6.3 Disbursements from the *TR clearing account* authorised by the *IESO Board* pursuant to section 4.18.2 of Chapter 8 shall be used by the *IESO* in accordance with section 4.7.

3.6.4 Any net revenues received from the sale of a *TR* in a *TR auction,* along with the hourly balance accrued in the *transmission charge reduction fund,* shall be credited to the *TR clearing account* and shall be used in accordance with the provisions of section 3.6.3 and of Chapter 8.

3.7 [Intentionally left blank – section deleted]

3.7.1 [Intentionally left blank – section deleted]

3.7.2 [Intentionally left blank – section deleted]

3.8 Hourly Settlement Amounts for Operating Deviations

3.8.1 The *IESO* may adjust by means of a debit the *settlement statement* of any *market participant* who is compensated in the market for providing *operating reserve* from a specific *registered facility* that operates in a way that does not provide the service for which it has been paid. Such debits in any *settlement hour* may represent either the decreased value of services provided in that same *settlement hour*, or the value of *operating reserve* services deemed not to have been provided in earlier *dispatch hours* as a result of failure to perform when called in the later *dispatch hour* associated with that *settlement hour*. The hourly *settlement* debits for failure to provide *energy* from *operating reserve* when it is called are set forth in this section 3.8.

3.8.2 An *operating reserve* shortfall *settlement* debit may be assessed on any *market participant* 'k' responsible for a *registered facility* at *RWM* m, which will be *registered facility* "k/m" for the purpose of this section 3.8.2 and of section 3.8.4, that is scheduled by the *IESO* to provide *class r reserve* of class 1or 2 (i.e., *ten-minute reserve* or *thirty-minute reserve*) and then fails to provide *energy* from that class of *operating reserve* when instructed to do so by the *IESO* according to these *market rules*. The amount of *market participant* 'k's *operating reserve* shortfall *settlement* debit for *class r reserve* for *settlement hour* 'h' ("$ORSSD_{k,r,h}$") is determined as follows:

3.8.2.1 the *energy* shortfall fraction for *class r reserve* for *registered facility* k/m in *metering interval* 't' of *settlement hour* 'h' ("$ORESF_{k,r,h}^{m,t}$") is defined as follows:

where *operating reserve* is provided from a *generator,* or from an *electricity storage participant* injecting *energy* :

$$ORESF_{k,r,h}^{m,t} = MAX\left[(SE_{k,h}^{m,t} - AQEI_{k,h}^{m,t})/SE_{k,h}^{m,t}, 0\right]$$

where *operating reserve* is provided from a *dispatchable load* or from an *electricity storage participant* withdrawing *energy*:

$$ORESF_{k,r,h}^{m,t} = MAX\left[(AQEW_{k,h}^{m,t} - SE_{k,h}^{m,t}) / AQEW_{k,h}^{m,t}, 0\right]$$

in either of the above cases:

$ORESF_{k,r,h}^{m,t}$ shall be 0 if:

a. $SE_{k,h}^{m,t}=0$;

b. no class r reserve is activated for registered facility k/m, at RWM m during metering interval 't' of settlement hour 'h'; or

c. $ORESF_{k,r,h}^{m,t}$ is less than the value established by the *IESO Board* and *published* in accordance with section 3.8.2.4.

Where:

$SE_{k,h}^{m,t}$ = total scheduled *energy*, including activated *operating reserve*, from *registered facility* k/m at *RWM* m, determined on the basis of the *dispatch instructions* for *metering interval* 't' of *settlement hour* 'h'.

3.8.2.2 define $\Sigma_{T,H}\ ORRSC_{k,r,H}^{m,T}$ = total *settlement* credits for *class r reserve* (including congestion management *settlement* credits related to *class r reserve*) during the lesser of:

a. where *registered facility* k/m has not been activated to provide *operating reserve* during the 719 *settlement hours* preceding the current *settlement hour*, all *metering intervals* during the current *settlement hour* and all of the *metering intervals* within the 719 *settlement hours* preceding the current *settlement hour*; or

b. where *registered facility* k/m has been activated to provide *operating reserve* during the 719 *settlement hours* preceding the current *settlement hour* all *metering intervals* between the current *metering interval*, including the current *metering interval* and the most recent *metering interval* preceding the current *metering interval*, in which the *market participant* 'k' received a *dispatch instruction* for the activation of *class r reserve* from *registered facility* k/m.

3.8.2.3 $ORSSD_{k,r,h}$ is defined as follows:

a. where the most recent *dispatch instruction* issued to the *market participant* for the activation of *class r reserve* prior to the current *metering interval* was issued within the 719 *settlement hours* preceding the current *settlement hour* and resulted in $ORESF_{k,r,h}^{m,t}$ that exceeded the value referred to in section 3.8.2.4,
$ORSSD_{k,r,h} = \sum_{m,t}[ORESF_{k,r,h}^{m,t} \times \sum_{T,H}(ORRSC_{k,r,H}^{m,T})]$; or

b. in all other cases,
$ORSSD_{k,r,h} = \sum_{m,t} [ORESF_{k,r,h}^{m,t} \times \sum_{T,H} (ORRSC_{k,r,H}^{m,T})/2]$

where:

t = all *metering interval*s in *settlement hour* 'h' in which $ORESF_{k,r,h}^{m,t}$ exceeds the value referred to in section 3.8.2.4

T = all *metering intervals* referred to in section 3.8.2.2 (a), or 3.8.2.2 (b) as the case may be

H = all *settlement hours* referred to in section 3.8.2.2 (a), or 3.8.2.2 (b) as the case may be

m = all RWMs serving market participant 'k's registered facilities

3.8.2.4 For the purposes of section 3.8.2.1(c), the *IESO Board* shall establish, and the *IESO* shall *publish,* a value below which $ORESF_{k,r,h}^{m,t}$ shall be set at zero. Where the *IESO Board* revises such value:

a. any such revised value shall be *published* by the *IESO*; and

b. the revised value shall not be used for the purposes of calculating $ORESF_{k,r,h}^{m,t}$ until 31st *trading day* following the date of publication.

3.8.3 [Intentionally left blank]

3.8.4 [Intentionally left blank]

3.8.4.1 [Intentionally left blank]

3.8.4.2 [Intentionally left blank]

3.8.4.3 [Intentionally left blank]

3.8.5 [Intentionally left blank]

3.8A Hourly Settlement Amounts for Intertie Offer Guarantees

3.8A.1 The *market prices* determined by the *real-time market schedule* provided by the *IESO* used for the *settlement* of a *boundary entity* associated with an *intertie metering point* will sometimes deviate from:

in the case of an import transaction not scheduled in the *schedule of record*, its accepted *offer* prices in the *pre-dispatch market schedule* (the "*projected market schedule*") in ways that, based on the *real-time dispatch process*, imply a change to *market participant* 'k's net operating profits relative to the operating profits implied by the *pre-dispatch market schedule* for that *boundary entity*; or

in the case of an import transaction scheduled in the *schedule of record*, its accepted *offer* prices in the *schedule of record* in ways that, based on the *real-time dispatch process*, imply a change to *market participant* 'k's net operating profits relative to the operating profits implied by the *schedule of record* for that *boundary entity*.

When this occurs but subject to section 3.8A.3, *market participant* 'k' associated with that *boundary entity* for *settlement hour* 'h' shall receive as compensation:

3.8A.1.1 in the case of an import transaction not scheduled in the *schedule of record*, a *real-time intertie offer* guarantee ($RT_IOG_{k,h}$) *settlement* credit for the import of *energy* into the *IESO-administered markets* equal to the cumulative losses resulting from a negative change in implied operating profits over the course of each *settlement hour*, resulting from such *settlement*, calculated in accordance with section 3.8A.2; or

3.8A.1.2 in the case of an import transaction scheduled in the *schedule of record*, the larger of a real-time *intertie offer* guarantee *settlement* credit ($RT_IOG_{k,h}$) or the day-ahead *intertie offer* guarantee *settlement* credit ($DA_IOG_{k,h}$) for the import of *energy* into the *IESO-administered markets* equal to the cumulative losses resulting from a negative change in implied operating profits over the course of each *settlement hour*, resulting from such *settlement*, calculated in accordance with section 3.8A.2 or 3.8A.2B as the case may be.

Real-Time Intertie Offer Guarantee

3.8A.2 The real-time *intertie offer* guarantee *settlement* credit for *market participant* 'k' for *settlement hour* 'h' ("$RT_IOG_{k,h}$") shall be determined by the following equation:

Let OP(P,Q,B) be a profit function of Price (P), Quantity (Q) and an N by 2 matrix (B) of *price-quantity pairs*:

$$OP(P,Q,B) = P \cdot Q - \sum_{n=1}^{s^*} P_n \cdot (Q_n - Q_{n-1}) - (Q - Q_{s^*}) \cdot P_{s^*+1}$$

Using matrix notation for parameter 'B' this may be expressed as follows:

$$OP(P,Q,B) = P \cdot Q - \sum_{n=1}^{s^*} [B[n,1] \cdot (B[n,2] - B[n-1,2])] - [(Q - B[s^*,2]) \cdot B[s^*+1,1]]$$

Where:
s^* is the highest indexed row of B such that $Q_{s^*} \leq Q \leq Q_n$ and where, $Q_0=0$

'P' is $EMP_h^{i,t}$: the real-time 5-minute *energy market price* at the applicable *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h'

'Q' is $MQSI_{k,h}^{i,t}$: the market quantity scheduled for injection in the *market schedule* by *market participant* 'k' at *intertie metering point* 'i' in *metering interval* 't' of *settlement hour* 'h'

'B' is matrix $BE_{k,h}^{i,t}$ of N price-quantity pairs offered by *market participant* 'k' to supply *energy* from a particular *boundary entity* associated with an *intertie metering point* 'i' in the *IESO-administered markets*, during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by offered price where offered prices are in column 1 and offered quantities are in column 2.

Using the terms below, let $RT_IOG_{k,h}$ be expressed as follows:

$$RT_IOG_{k,h} = EIM_{k,h}$$

Where:

$EIM_{k,h}$ represents that component of the real-time *intertie offer* guarantee *settlement* credit for *market participant* 'k' during *settlement hour* 'h' attributable to import of *energy* into the *IESO-administered markets* at all relevant *intertie metering points* 'i' in accordance with the rationale referred to in section 3.8A.1 and is calculated as follows:

$$EIM_{k,h} = \sum_I (-1) \bullet MIN\left[0, \sum_T OP(EMP_h^{i,t}, MQSI_{k,h}^{i,t}, BE)\right]$$

Such that:

I is the set of all relevant *intertie metering points* 'i'

T is the set of all *metering intervals* 't' in *settlement hour* 'h'

$EMP_h^{i,t}$ is the real-time 5-minute *energy market price* at the applicable *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h'

Day-Ahead Intertie Offer Guarantee

3.8A.2A The day-ahead *intertie offer* guarantee *settlement* credit for *market participant* 'k' for *settlement hour* 'h' ("$DA_IOG_{k,h}$") shall be determined for import transactions that are not part of a day-ahead linked wheel.

3.8A.2B The day-ahead *intertie offer* guarantee *settlement* credit for *market participant* 'k' for *settlement hour* 'h' ("$DA_IOG_{k,h}$") shall be determined by the following equation:

$DA_BE_{k,h}^{i,t}$ is the offer matrix of N price-quantity pairs for the eligible import transaction scheduled in the *schedule of record* for *market participant* 'k' during *metering interval* 't' for settlement hour 'h' at *intertie metering point* 'i' arranged in ascending order by offered price where offered prices are in column 1 and offered quantities are in column 2.

Let OP(P,Q,B) be a profit function of Price (P), Quantity (Q) and an N by 2 matrix (B) of *price-quantity pairs*:

$$OP(P,Q,B) = P \cdot Q - \sum_{n=1}^{s^*} P_n \cdot (Q_n - Q_{n-1}) - (Q - Q_{s^*}) \cdot P_{s^*+1}$$

Using matrix notation for parameter 'B' this may be expressed as follows:

$$OP(P,Q,B) = P \cdot Q - \sum_{n=1}^{s^*} [B[n,1] \cdot (B[n,2] - B[n-1,2])] - [(Q - B[s^*,2]) \cdot B[s^*+1,1]]$$

Where:

s^* is the highest indexed row of B such that $Q_{s^*} \leq Q \leq Q_n$ and where, $Q_0=0$

'P' is $EMP_h^{i,t}$: the real-time 5-minute *energy market price* at the applicable *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h'

'Q' is the minimum of:

$DA_DQSI_{k,h}^{i,t}$: the *schedule of record* constrained quantity scheduled for injection by *market participant* 'k' for an import transaction at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h'; or

$DQSI_{k,h}^{i,t}$: the real-time constrained quantity scheduled for injection by *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h';

'B' is matrix $DA_BE_{k,h}^{i,t}$: *energy offers* submitted into the *schedule of record*, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered price in each *price-quantity pair* where offered prices are in column 1 and offered quantities are in column 2;

such that the day-ahead *intertie offer* guarantee is formulated as follows:

The principles for the settlement of the day-ahead *intertie offer* guarantee are as follows:

1. Component 1: Any shortfall in payment on the real-time import flow of the *schedule of record* will be based upon the real-time revenue received for that amount of *energy* in comparison with the costs submitted in the importer's day-ahead *offer*;
2. Component 2: For the portion of *schedule of record* that is not implemented in the real-time *dispatch* schedule, the day-ahead *intertie offer* guarantee will guarantee the cost incurred of arranging the import (where the real-time *offer* price is less than day ahead *offer* price) or subtract any revenue gained (where the real-time *offer* price is greater than the day-ahead *offer* price) [1]; and
3. Component 3: Any income from real-time congestion management *settlement* credit (CMSC) included in an importer's *schedule of record* delivered in real-time will be used to reduce the day-ahead *intertie offer* guarantee payment.

The Day-Ahead Intertie Offer Guarantee is calculated as follows:

$$DA_IOG_{k,h} = MAX\left[0, \sum_{T}\left(DA_IOG_COMP1_{k,h}^{i,t} + DA_IOG_COMP2_{k,h}^{i,t} - DA_IOG_COMP3_{k,h}^{i,t}\right)\right]$$

Where:

T = set of all *metering intervals* 't' in the set of all *settlement hour* 'h'

[1] Where the real-time *offer* is equal to the day-ahead *offer*, the cost/gain is equal to zero (0).

Component 1

Component 1 includes any shortfall in payment on the delivered real-time *dispatch* of the *schedule of record* based upon the real-time revenue received for that amount of *energy* in comparison with the costs as represented in the importer's day-ahead *offer*. Component 1 is calculated as follows:

$DA_IOG_COMP1_{k,h}^{i,t}$ = As-offered day-ahead costs for the minimum of the importer's *schedule of record* and the real-time constrained schedule for the interval minus all real-time revenue received over the interval for that amount of *energy*

$$DA_IOG_COMP1_{k,h}^{i,t} = (-1)\times OP\left(EMP_{h}^{i,t}, MIN\left(DA_DQSI_{k,h}^{i,t}, DQSI_{k,h,}^{i,t}\right), DA_BE_{k,h}^{i,t}\right)$$

Component 2

If, as a result of economic selection, a portion of the *schedule of record* is not implemented in the real-time *dispatch* schedule, the day-ahead *intertie offer* guarantee:

Guarantees the cost of arranging the delivery if the real-time *offer* is less than the day-ahead *offer*; or

Subtracts any gain where the real-time *offer* is greater than the day-ahead *offer*.

If there are no real-time *energy offers* submitted by the *market participant* for any portion of the day-ahead constrained schedule, the real-time *energy offers* for that portion of *energy* will be set to MMCP (*Maximum Market Clearing Price*) for the purposes of calculating Component 2.

If the real-time *energy offers* for any portion of the day-ahead constrained schedule is below $0.00 $/MWh (i.e. negative), the real-time *energy offers* for that portion of *energy* will be set to $0.00 $/MWh for the purposes of calculating Component 2.

Component 2 is calculated as follows:

$DA_IOG_COMP2_{k,h}^{i,t}$ = As-offered day-ahead costs for the difference between:

- the minimum of the importer's *schedule of record* quantity, or the real-time constrained schedule; and
- the minimum of the importer's *schedule of record* quantity.

over the interval minus all real-time *energy offers* (with a minimum limit of zero) over the interval for that amount of *energy*

$$DA_IOG_COMP2_{k,h}^{i,t} = XDA_BE_{k,h}^{i,t} - MAX\left(0, XBE_{k,h}^{i,t}\right)$$

Where:

Let $XBE_{k,h}^{i,t}$ be the function which calculates the area under the curve created by an n x 2 matrix (B) of offered *price-quantity pairs*:

$$\left[\sum_{n=p^*}^{s^*} P_n \times \left(Q_n - Q_{n-1}\right)\right] + \left(Q - Q_{s^*}\right) \times P_{s^*+1}$$

where matrix (B) is *energy offers* submitted in real-time, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* ‘k’ at *intertie metering point* ‘i’ during *metering interval* ‘t’ of *settlement hour* ‘h’ arranged in ascending order by the offered price in each *price quantity pair* where offered prices ‘P’ are in column 1 and offered quantities ‘Q’ are in column 2

Let $XDA_BE_{k,h}^{i,t}$ be the function which calculates the area under the curve created by an n x 2 matrix (B) of offered *price-quantity pairs*:

$$\left[\sum_{n=c^*}^{d^*} P_n \times \left(Q_n - Q_{n-1}\right)\right] + \left(Q - Q_{d^*}\right) \times P_{d^*+1}$$

where matrix (B) is *energy offers* submitted in pre-dispatch, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* ‘k’ at *intertie metering point* ‘i’ during *metering interval* ‘t’ of *settlement hour* ‘h’ arranged in ascending order by the offered price in each *price quantity pair* where offered prices ‘P’ are in column 1 and offered quantities ‘Q’ are in column 2

c^* = the highest indexed row of matrix $XDA_BE_{k,h}^{i,t}$ such that $Q_{c^*} \leq \min[DA_DQSI_{k,h}^{i,t}, DQSI_{k,h}^{i,t},] \leq Q_n$ and where $Q_{c^*-1} = \min[DA_DQSI_{k,h}^{i,t}, DQSI_{k,h}^{i,t}]$ and where if $Q_{c^*} < Q_{c^*-1}$, let $Q_{c^*} = Q_{c^*-1}$

d^* = the highest indexed row of matrix XDA_BEk,hi,t such that $Qd^* \leq DA_DQSIk,hi,t \leq Qn$

p^* = the highest indexed row of matrix XBEk,hi,t such that $Qp^* \leq \min[DA_DQSIk,hi,t, DQSIk,hi,t] \leq Qn$ and where $Qp^*-1 = \min[DA_DQSIk,hi,t, DQSIk,hi,t]$ and where if $Qp^* < Qp^*-1$, let $Qp^* = Qp^*-1$

s^* = the highest indexed row of matrix $XBE_{k,h}^{i,t}$ such that $Q_{s^*} \leq DA_DQSI_{k,h}^{i,t} \leq Q_n$

Component 3

The DA-IOG payment for an import will be reduced by the income received from real time congestion management *settlement* credit (CMSC) for the importer's *schedule of record* delivered in real-time.

The importer's *schedule of record* will be measured against both the real-time constrained schedule and the real-time unconstrained schedule to determine the amount of revenue from CMSC that should be included in the day-ahead *intertie offer* guarantee calculation.

For any interval, there are six possible orderings of the amount of an importer's capacity that may be included in the *schedule of record*, the real-time unconstrained schedule and the real-time constrained schedule. Table 0-1: Ordering of Importer's Capacity and Day-Ahead Intertie Offer Guarantee Component 3 summarizes the six possible orderings and the inclusion of Component 3 in the day-ahead *intertie offer* guarantee calculation.

For the purposes of determining the applicable CMSC in Component 3, the o*ffer price* is subject to Section 3.5.6.

Table 0-1: Ordering of Importer's Capacity and Day-Ahead Intertie Offer Guarantee Component 3

Scenario	Ordering	Component 3 - CMSC Included?
1	DQSI >= MQSI >= DA_DQSI	N
2	MQSI >= DQSI >= DA_DQSI	N
3	DQSI > DA_DQSI > MQSI	Y (Partial CMSC)
4	MQSI > DA_DQSI > DQSI	Y (Partial CMSC)
5	DA_DQSI >= DQSI > MQSI	Y (All CMSC)
6	DA_DQSI >= MQSI > DQSI	Y (All CMSC)

Component 3 is calculated as follows :

$DA_IOG_COMP3_{k,h}^{i,t}$ = Income received from real time congestion management *settlement* credits (CMSC) for the importer's *schedule of record* delivered in real-time over the interval

Component 3 is only calculated when the real-time CMSC for the same interval is a value other than zero.

Scenario 1

$DA_IOG_COMP3_{k,h}^{i,t} = 0$

Scenario 2

$DA_IOG_COMP3_{k,h}^{i,t} = 0$

Scenario 3

$$DA_IOG_COMP3_{k,h}^{i,t} = OP\left(EMP_{h}^{i,t}, MQSI_{k,h}^{i,t}, BE_{k,h}^{i,t}\right) - OP\left(EMP_{h}^{i,t}, DA_DQSI_{k,h}^{i,t}, BE_{k,h}^{i,t}\right)$$

Scenario 4

$$DA_IOG_COMP3_{k,h}^{i,t} = OP\left(EMP_{h}^{i,t}, DA_DQSI_{k,h}^{i,t}, BE_{k,h}^{i,t}\right) - OP\left(EMP_{h}^{i,t}, DQSI_{k,h}^{i,t}, BE_{k,h}^{i,t}\right)$$

Scenario 5

$DA_IOG_COMP3_{k,h}^{i,t}$ = Congestion management *settlement* credit calculated as per Section 3.5.

Scenario 6

$DA_IOG_COMP3_{k,h}^{i,t}$ = Congestion management *settlement* credit calculated as per Section 3.5.

Intertie Offer Guarantee Settlement

3.8A.3 The cumulative *intertie offer* guarantee *settlement* credits payable to a *market participant* for any and all applicable *settlement hours* in the *real-time market* for

an *energy billing period* shall be adjusted by the *IESO* in accordance with section 3.8A.4 to nullify such credits where:

3.8A.3.1 that *market participant* has submitted one or more *energy offers* and one or more *energy bids* as contemplated by section 3.5.8.1 of Chapter 7 for the same *dispatch interval*; or

3.8A.3.2 the *market assessment unit* has determined that the *market participant* has an agreement or arrangement to share the *intertie offer* guarantee *settlement* credit with one or more other *market participants* and they have submitted one or more *energy offers* and one or more *energy bids* as contemplated by section 3.5.8.1 of Chapter 7 for the same *dispatch interval*; or

3.8A.3.3 the *market participant* has one or more import transactions in the *schedule of record* at an *intertie metering point* and where:

the same import transaction is subsequently scheduled in the corresponding *metering interval* of the corresponding *settlement hour* in the *real-time market*; and

the *market participant* submits one or more *schedule of record* and/or real-time *energy bids* as contemplated by section 3.5.8.1 of Chapter 7 for the same *dispatch interval*; and

at least one of such *energy offers* and one of such *energy bids* is scheduled; and

where the export transaction of such *energy bid* is settled at the *energy market* price at the *intertie metering point* and not a *settlement* floor price as set out in section 3.3.2.1A.

For certainty, any *market participant* shall have recourse to the dispute resolution provisions of section 2 of Chapter 3 if it believes that the *market assessment unit* did not have reasonable grounds for making the determination that the *market participant* had any such agreement or arrangement with another *market participant* as described in section 3.8A.3.2.

3.8A.4 The combined day-ahead and real-time *intertie offer* guarantees and intertie offer guarantee *settlement* credit offset ("IOG Offset") process is as follows. Any adjustment made by the *IESO* under section 3.8A.3 shall be applied with respect to any export transaction in the constrained schedule for *market participant* 'k' in each *settlement hour* 'h' for which *market participant* 'k' is entitled to receive a real-time or day-ahead *intertie offer* guarantee *settlement* credit meeting the conditions set out in section 3.8A.3. The total amount offset shall be limited by

the cumulative quantity of the export transactions expressed in the constrained schedule for that *settlement hour* and shall not exceed the total combined real-time and day-ahead *intertie offer* guarantee *settlement* credits received for the *settlement hour*. Where the cumulative quantity of the export transactions expressed in the constrained schedule for the *settlement hour* is less than the cumulative quantity of imports triggering real-time and day-ahead *intertie offer* guarantee *settlement* credits for that same *settlement hour*, the real-time and day-ahead *intertie offer* guarantee *settlement* credits will be offset in ascending order from the import transaction with the smallest real-time and/or day-ahead *intertie offer* guarantee *settlement* rate to the import transaction attracting the largest real-time and/or largest day-ahead *intertie offer* guarantee *settlement* rate and only up until the point at which the total quantity of import transactions equals the total quantity of export transactions, and may be expressed as described in the general rule that follows.

The offset process described in this section shall apply to:

real-time *intertie offer* guarantee *settlement* credits meeting the criteria of section 3.8A.3.1; or

real-time *intertie offer* guarantee *settlement* credits or day-ahead *intertie offer* guarantee *settlement* credits meeting the criteria of section 3.8A.3.3.

For the purposes of this calculation all applicable real-time or day-ahead *intertie offer* guarantee *settlement* credits meeting the criteria described above, attributable to *market participant* 'k' for *settlement hour* 'h' shall be arranged in ascending order by rate (dollars per megawatt per transaction), and subject to the following decision rules:

a. [Intentionally left blank – section deleted]

b. Where a day-ahead *intertie offer* guarantee *settlement* credit is associated with the import transaction, but no real-time *intertie offer* guarantee *settlement* credit was applicable, the day-ahead *intertie offer* guarantee *settlement credit* will be included;

c. Where a real-time *intertie offer* guarantee *settlement* credit is associated with the import transaction, but no day-ahead *intertie offer* guarantee *settlement* credit is applicable, the real-time *intertie offer* guarantee *settlement* credit will be included;

The ordering of these *settlement amounts* is described in terms of a general rule as follows:

Let $MI_{k,h}^{t}$ [N,13] be an N by 13 matrix of N pairs of import quantities scheduled for injection by *market participant* 'k' in the real-time *dispatch schedule* and/or the constrained schedule from the DACP *schedule of record* in the *settlement hour* 'h' ($DA_DQSI_{k,h}^{i}$ and/or $DQSI_{k,h}^{i}$ as the case may be) paired with the corresponding day-ahead *intertie offer* guarantee, the component of the real-time *intertie offer* guarantee *settlement* credit, DA-IOG rate, RT-IOG rate, DA Offset DQSW, DA-Offset Flag, Settlement rate, (gross) IOG$, RT Offset DQSW, IOG Offset $, (net) IOG $ for all *intertie metering points* 'i' arranged in ascending order by *settlement* rate in each row. Columns 1 through 4 are original inputs to the matrix, while columns 5 through 13 are derived.

The general rules to settle IOG are as follows:

Note: $MI_{k,h}$ [N,13] matrix has been transposed such that the columns are on the rows.

Event Type	General Rule
Matrix $MI_{k,h}$ [Row 'n', Column 1]	$DA_DQSI_{k,h}^{i}$ Associated with the settlement amount in column 3
Matrix $MI_{k,h}$ [Row 'n', Column 2]	$DQSI_{k,h}^{i}$ Associated with the settlement amount in column 3 and 4
Matrix $MI_{k,h}$ [Row 'n', Column 3]	$DA_IOG_{k,h}^{i}$
Matrix $MI_{k,h}$ [Row 'n', Column 4]	$RT_IOG_{k,h}^{i}$
Matrix $MI_{k,h}$ [Row 'n', Column 5]	$MI_{k,h}$ [n,5] $\{DA_IOG_RATE_{k,h}^{i}\}$=

	$DA_IOG_{k,h}^{i}$ / MIN($DA_DQSI_{k,h}^{i}$, $DQSI_{k,h}^{i}$)
Matrix $MI_{k,h}$ [Row 'n', Column 6]	$MI_{k,h}$ [n,6] {$RT_IOG_RATE_{k,h}^{i}$}= $RT_IOG_{k,h}^{i}$ / $DQSI_{k,h}^{i}$
Matrix $MI_{k,h}$ [Row 'n', Column 7]	$MI_{k,h}$ [n,7] {$DA_OFFSET_DQSW_{k,h}^{i}$}
Matrix $MI_{k,h}$ [Row 'n', Column 8]	$MI_{k,h}$ [n,8] { $DA_OFFSET_FLAG_{k,h}^{i}$ } = "Y" or "N" Such that: $DA_OFFSET_FLAG_{k,h}^{i}$ = "Y" when {$DA_OFFSET_DQSW_{k,h}^{i}$}> 50% of MIN{$DA_DQSI_{k,h}^{i}$,$DQSI_{k,h}^{i}$ }
Matrix $MI_{k,h}$ [Row 'n', Column 9]	$MI_{k,h}$ [n,9] {$IOG_SETTLEMENT_RATE_{k,h}^{i}$} = $RT_IOG_RATE_{k,h}^{i}$ if $DA_OFFSET_FLAG_{k,h}^{i}$ = "Y" ; OR $MI_{k,h}^{i}$ [n,9] {$IOG_SETTLEMENT_RATE_{k,h}^{i}$} = MAX[$DA_IOG_RATE_{k,h}^{i}$, $RT_IOG_RATE_{k,h}^{i}$] if $DA_OFFSET_FLAG_{k,h}^{i}$ = "N"; Subject to: $MI_{k,h}$ [n,9] >= $MI_{k,h}$ [n-1,9]; $MI_{k,h}$ [1,9] = MIN[$MI_{k,h}$ [1 to N,9]]; [$MI_{k,h}$ [1 to N,9]] <> 0
Matrix $MI_{k,h}$ [Row 'n', Column 10]	$MI_{k,h}^{i}$ [n,10] {$IOG\$_{k,h}^{i}$} = the $DA_IOG\$_{k,h}^{i}$ or $RT_IOG\$_{k,h}^{i}$ associated with the Settlement Rate $_{k,h}^{i}$ (i.e. $RT_IOG_RATE_{k,h}^{i}$ or MAX($DA_IOG_RATE_{k,h}^{i}$,$RT_IOG_RATE_{k,h}^{i}$))
Matrix $MI_{k,h}$ [Row 'n', Column 11]	$MI_{k,h}$ [n,11] {$RT_OFFSET_DQSW_{k,h}^{i}$ }
Matrix $MI_{k,h}$ [Row 'n', Column 12]	$MI_{k,h}$ [n,12] {$IOG_OFFSET_{k,h}^{i}$ }

Matrix $MI_{k,h}$ [Row 'n', Column 13]	$MI_{k,h}$ [n,13] {$Net_IOG_{k,h}^{i}$ } = $MI_{k,h}$ [n,10] {$IOG\$_{k,h}^{i}$} - $MI_{k,h}^{i}$ [n,12] {$IOG_OFFSET_{k,h}^{i}$ }

The outcomes from the general rules are as follows

	A	B	C	D
Event Type	An import transaction scheduled day ahead receiving a DA-IOG but no RT-IOG and is not offset Day Ahead	An import transaction scheduled day ahead receiving a DA-IOG but no RT-IOG and is offset Day Ahead	An import transaction scheduled only in the real-time and receiving a RT-IOG but no DA-IOG	An import transaction scheduled both in the day ahead and in the real-time receiving DA-IOG and RT-IOG.
Matrix $MI_{k,h}$ [Row 'n', Column 1]	$DA_DQSI_{k,h}^{i}$	$DA_DQSI_{k,h}^{i}$	NULL	$DA_DQSI_{k,h}^{i}$
Matrix $MI_{k,h}$ [Row 'n', Column 2]	$DQSI_{k,h}^{i}$	$DQSI_{k,h}^{i}$	$DQSI_{k,h}^{i}$	$DQSI_{k,h}^{i}$
Matrix $MI_{k,h}$ [Row 'n', Column 3]	$DA_IOG_{k,h}^{i}$	$DA_IOG_{k,h}^{i}$	$DA_IOG_{k,h}^{i}$ = NULL	$DA_IOG_{k,h}^{i}$
Matrix $MI_{k,h}$ [Row 'n', Column 4]	$RT_IOG_{k,h}^{i}$ = NULL	$RT_IOG_{k,h}^{i}$ = NULL	$RT_IOG_{k,h}^{i}$	$RT_IOG_{k,h}^{i}$
Matrix $MI_{k,h}$ [Row 'n', Column 5]	{$DA_IOG_RATE_{k,h}^{i}$}	{$DA_IOG_RATE_{k,h}^{i}$}	NULL	{$DA_IOG_RATE_{k,h}^{i}$}
Matrix $MI_{k,h}$ [Row 'n', Column 6]	{$RT_IOG_RATE_{k,h}^{i}$}= NULL	{$RT_IOG_RATE_{k,h}^{i}$}= NULL	{$RT_IOG_RATE_{k,h}^{i}$}	{$RT_IOG_RATE_{k,h}^{i}$}
Matrix $MI_{k,h}$ [Row 'n', Column 7]	{$DA_OFFSET_DQSW_{k,h}^{i}$} = 0	{$DA_OFFSET_DQSW_{k,h}^{i}$} > 0	NULL	{$DA_OFFSET_DQSW_{k,h}^{i}$} >= 0

	A	B	C	D
Matrix $MI_{k,h}$ [Row 'n', Column 8]	{DA_OFFSET_FLAG$_{k,h^i}$} = "N"	{DA_OFFSET_FLAG$_{k,h^i}$} = "Y"	NULL	{DA_OFFSET_FLAG$_{k,h^i}$} = "Y" or "N"
Matrix $MI_{k,h}$ [Row 'n', Column 9]	$MI_{k,h}$ [n,9] {IOG_SETTLEMENT_RATE$_{k,h^i}$} = {DA_IOG_RATE$_{k,h^i}$}	NULL	$MI_{k,h}$ [n,9] {IOG_SETTLEMENT_RATE$_{k,h^i}$} = {RT_IOG_RATE$_{k,h^i}$}	$MI_{k,h}$ [n,9] {IOG_SETTLEMENT_RATE$_{k,h^i}$} = {RT_IOG_RATE$_{k,h^i}$} or MAX(DA_IOG_RATE$_{k,h^i}$, RT_IOG_RATE$_{k,h^i}$)
Matrix $MI_{k,h}$ [Row 'n', Column 10]	$MI_{k,h}$ [n,10] {IOG$_{k,h^i}$} = DA_IOG$_{k,h^i}$	NULL	$MI_{k,h}$ [n,10] {IOG$_{k,h^i}$} = RT_IOG$_{k,h^i}$	$MI_{k,h}$ [n,10] {IOG$_{k,h^i}$} = {RT_IOG$_{k,h^i}$} or MAX(DA_IOG$_{k,h^i}$, RT_IOG$_{k,h^i}$)
Matrix $MI_{k,h}$ [Row 'n', Column 11]	$MI_{k,h}$ [n,11] {RT_OFFSET_DQSW$_{k,h^i}$} >= 0	NULL	$MI_{k,h}$ [n,11] {RT_OFFSET_DQSW$_{k,h^i}$} >= 0	$MI_{k,h}$ [n,11] {RT_OFFSET_DQSW$_{k,h^i}$} >= 0
Matrix $MI_{k,h}$ [Row 'n', Column 12]	$MI_{k,h}$ [n,12] {IOG_OFFSET$_{k,h^i}$} >= 0	NULL	$MI_{k,h}$ [n,12] {IOG_OFFSET$_{k,h^i}$} >= 0	$MI_{k,h}$ [n,12] {IOG_OFFSET$_{k,h^i}$} >= 0
Matrix $MI_{k,h}$ [Row 'n', Column 13]	$MI_{k,h}$ [n,13] {Net_IOG$_{k,h^i}$} = $MI_{k,h}$ [n,10] {IOG$_{k,h^i}$} - $MI_{k,h}$ [n,12] {IOG_OFFSET$_{k,h^i}$}	NULL	$MI_{k,h}$ [n,13] {Net_IOG$_{k,h^i}$} = $MI_{k,h}$ [n,10] {IOG$_{k,h^i}$} - $MI_{k,h}$ [n,12] {IOG_OFFSET$_{k,h^i}$}	$MI_{k,h}$ [n,13] {Net_IOG$_{k,h^i}$} = $MI_{k,h}$ [n,10] {IOG$_{k,h^i}$} - $MI_{k,h}$ [n,12] {IOG_OFFSET$_{k,h^i}$}

The Day-Ahead IOG rate (DA_IOG $RATE_{k,h}^{i}$) column 5, at an *intertie metering point* 'i' in *settlement hour* 'h' is calculated using the day ahead constrained import schedule value in columns 1 (DA_$DQSI_{k,h}^{i}$) and real time import schedule value in column 2 ($DQSI_{k,h}^{i}$) and the DA_$IOG_{k,h}^{i}$ value in Column 3 of each unique row 'n' in matrix $MI_{k,h}$ as follows:

$$\text{DA_IOG RATE}_{k,h}^{i} = \text{IF}\left[\text{DA_IOG}_{k,h}^{i} \text{ is not NULL}, \frac{\text{DA_IOG}_{k,h}^{i}}{\text{MIN}(\text{DA_DQSI}_{k,h}^{i}, \text{DQSI}_{k,h}^{i})}, 0\right]$$

The Real-Time IOG rate (RT_IOG_$RATE_{k,h}^{i}$) column 6 at an *intertie metering point* 'i' in *settlement hour* 'h' is calculated using the real-time constrained import schedule of column 2 and the RT_$IOG_{k,h}^{i}$ value of Column 4 of each unique row 'n' in matrix $MI_{k,h}$ as follows:

$$\text{RT_IOG RATE}_{k,h}^{i} = \text{IF}\left[\text{RT_IOG}_{k,h}^{i} \text{ is not NULL}, \frac{\text{RT_IOG}_{k,h}^{i}}{\text{DQSI}_{k,h}^{i}}, 0\right]$$

The matrix is arranged in ascending order on DA_IOG_$RATE_{k,h}^{i}$ (Column 5) from the lowest rate to the highest rate.

The day-ahead export schedule quantity offset by *market participant* 'k' at an *intertie metering point* 'i' in *settlement hour* 'h' (DA_OFFSET_$DQSW_{k,h}^{i}$) column 7 is calculated using the day ahead constrained import schedule value in columns 1 (DA_$DQSI_{k,h}^{i}$), real time import schedule value in column 2 ($DQSI_{k,h}^{i}$) and the day ahead constrained export schedule value for the *market participant* for an hour as follows:

$$\text{DA_DQSW_REM}_{k,h} = \left[\text{MAX}\left[0, \left(\sum^{I} \text{DA_DQSW}_{k,h}^{I} - \sum_{i=1}^{n} \text{DA_OFFSET_DQSW}_{k,h}^{i}\right)\right]\right]$$

$$\text{DA_OFFSET_DQSW}_{k,h}^{i} = \text{MIN}\left[\text{DA_DQSI}_{k,h}^{i}, \text{DQSI}_{k,h}^{i}, \text{DA_DQSW_REM}_{k,h}\right]$$

Where:

I = set of all *intertie metering points* 'i'

n = The number of day ahead import transactions with DA_OFFSET_DQSW at each pass.

The day-ahead IOG offset flag ($DA_OFFSET\ FLAG_{k,h}^{i}$) column 8 at an *intertie metering point* 'i' in *settlement hour* 'h' is calculated using the values in column 7 $DA_OFFSET_DQSW_{k,h}^{i}$, columns 1 ($DA_DQSI_{k,h}^{i}$) and real time import schedule value in column 2 ($DQSI_{k,h}^{i}$) of each unique row 'n' in matrix $MI_{k,h}$ as follows:

$DA_OFFSET_FLAG_{k,h}^{i}$	=	$IF\left(DA_OFFSET_DQSW_{k,h}^{i} > [50\% \times MIN\left(DA_DQSI_{k,h,}^{i}, DQSI_{k,h}^{i}\right)], Y, N\right)$

The IOG offset rate ($IOG_SETTLEMENT_RATE_{k,h}^{i}$) column 9 at an *intertie metering point* 'i' in *settlement hour* 'h' is calculated using the values in Column 5 ($DA_IOG_RATE_{k,h}^{i}$) and Column 6 ($RT_IOG_RATE_{k,h}^{i}$) of each unique row 'n' in matrix $MI_{k,h}$ as follows:

$IOG_SETTLEMENT_RATE_{k,h}^{i}$	=	$IF\left[DA_OFFSET_FLAG_{k,h}^{i}=Y, RT_IOG_RATE_{k,h}^{i}, MAX(RT_IOG_RATE_{k,h}^{i}, DA_IOG_RATE_{k,h}^{i})\right]$
		Subject to: $MI_{k,h}[n,9] >= MI_{k,h}[n-1,9]$; $MI_{k,h}[1,9] = MIN[MI_{k,h}[1 \text{ to } N,9]]$; $[MI_{k,h}[1 \text{ to } N,9]] <> 0$

The IOG dollar amount ($IOG\$_{k,h}^{i}$) column 10 at an *intertie metering point* 'i' in *settlement hour* 'h' is the IOG dollar amount associated with the rate used in Column 9 ($IOG_SETTLEMENT_RATE_{k,h}^{i}$).

The matrix is arranged in ascending order of ($IOG_SETTLEMENT_RATE_{k,h}^{i}$) (Column 9) from the lowest rate to the highest rate.

The real-time export schedule quantity offset by *market participant* 'k' at an *intertie metering point* 'i' in *settlement hour* 'h' ($RT_OFFSET_DQSW_{k,h}^{i}$) column 11 is calculated using the real-time constrained import schedule values in column 2 ($DQSI_{k,h}^{i}$) and the real time constrained export schedule value for the *market participant* for an hour as follows:

$$RT_DQSW_REM_{k,h} = \left[MAX\left[0, \left(\sum^{I} DQSW^{i}_{k,h} - \sum_{i=1}^{n} RT_OFFSET_DQSW^{i}_{k,h} \right) \right] \right]$$

$$RT_OFFSET_DQSW_{k,h}{}^{i} = MIN\left[DQSI^{i}_{k,h}, RT_DQSW_REM_{k,h} \right]$$

Where:

I = set of all *intertie metering points* 'i'

n = The number of day ahead import transactions with DA_OFFSET_DQSW at each pass.

The IOG offset *settlement amount* for *market participant* 'k' at an *intertie metering point* 'i' in *settlement hour* 'h' ($IOG_OFFSET_{k,h}{}^{i}$) column 12 is calculated using column 9 ($IOG_SETTLEMENT_RATE_{k,h}{}^{i}$) and column 11($RT_OFFSET_DQSW_{k,h}{}^{i}$) as follows:

$$IOG_OFFSET_{k,h}{}^{i} = \left(IOG_SETTLEMENT_RATE^{i}_{k,h} \times RT_OFFSET_DQSW^{i}_{k,h} \right)$$

The IOG *settlement amount* for *market participant* 'k' at an *intertie metering point* 'i' in *metering settlement hour* 'h' ($NET_IOG_{k,h}{}^{i,}$) column 13 is calculated using column10 ($IOG\$_{k,h}{}^{i}$) and column 12 ($IOG_OFFSET_{k,h}{}^{i}$) as follows:

$$NET_IOG_{k,h}{}^{i} = \left(IOG\$^{i}_{k,h} - IOG_OFFSET^{i}_{k,h} \right)$$

3.8A.5 [Intentionally left blank – section deleted]

3.8A.6 [Intentionally left blank – section deleted]

Day-Ahead Intertie Offer Guarantee Adjustments

3.8A.7 [Intentionally left blank – section deleted]

3.8A.8 [Intentionally left blank – section deleted]

3.8A.9 [Intentionally left blank – section deleted]

3.8B Day Ahead Import Failure Charge

3.8B.1 The *IESO* shall apply the day-ahead import failure charge specified in section 3.8B.2 to a *market participant* for any quantity of *energy* scheduled for injection at an *intertie metering point* scheduled in the *schedule of record* where:

3.8B.1.1 the *market participant* fails either in whole or in part to schedule a *dispatch* quantity scheduled for injection in the *pre-dispatch schedule* in the corresponding *metering interval* of the corresponding *settlement hour* at the same *intertie metering point;* and,

3.8B.1.2 the *IESO* has not determined, nor has the *market participant* demonstrated to the satisfaction of the *IESO,* that the failure is due to bona fide and legitimate reasons as described in chapter 7, section 7.5.8B of these *market rules*; and

3.8B.1.3 the import transaction is not part of a day-ahead linked wheel.

3.8B.2 For all import transactions scheduled in the *schedule of record* and meeting the criteria of section 3.8B.1, the day-ahead import failure charge shall be formulated as follows:

Let OP(P,Q,B) be a profit function of Price (P), Quantity (Q) and an N by 2 matrix (B) of offered *price-quantity pairs*:

$$OP(P,Q,B) = P \cdot Q - \sum_{n=1}^{s^*} P_n \cdot (Q_n - Q_{n-1}) - (Q - Q_{s^*}) \cdot P_{s^*+1}$$

Using matrix notation for parameter 'B' this may be expressed as follows:

$$OP(P,Q,B) = P \cdot Q - \sum_{n=1}^{s^*} [B[n,1] \cdot (B[n,2] - B[n-1,2])] - [(Q - B[s^*,2]) \cdot B[s^*+1,1]]$$

Where:

s^* is the highest indexed row of B such that $Q_{s^*} \leq Q \leq Q_n$ and where, $Q_0=0$

'P' is $PD_EMP_h^{m,t}$: pre-dispatch projected *energy market price* applicable to all *delivery* points 'm' in the Ontario zone in *metering interval* 't' of *settlement hour* 'h;

'Q' is $DA_ISD_{k,h}^{i,t}$ as defined below; and

'B' is $DA_BE_{k,h}^{i,t}$: energy offers submitted into the *schedule of record*, represented as an N by 2 matrix of *price-quantity pairs* for each *market*

participant ‘k’ at *intertie metering point* ‘i’ during *metering interval* ‘t’ of *settlement hour* ‘h’ arranged in ascending order by the offered price in each *price-quantity pair* where offered prices are in column 1 and offered quantities are in column 2; or ‘B’ is $PD_BE_{k,h}^{i,t}$: energy *offers* submitted in pre-dispatch, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* ‘k’ at *intertie metering point* ‘i’ during *metering interval* ‘t’ of *settlement hour* ‘h’ arranged in ascending order by the offered price in each *price-quantity pair* where offered prices are in column 1 and offered quantities are in column 2.

the *offer* matrix of *price-quantity pairs* for the applicable import transaction that was submitted by *market participant* ‘k’ and scheduled in the *pre-dispatch of record* during *metering interval* ‘t’ for *settlement hour* ‘h’ of the *real-time trading day*

and,

Let $DA_ISD_{k,h}^{i,t}$ be the day-ahead import scheduling deviation quantity calculated for *market participant* ‘k’ at *intertie metering point* ‘i’ during *metering interval* ‘t’ of *settlement hour* ‘h’ as determined by the formula:

DA import scheduling deviation quantity ($DA_ISD_{k,h}^{i,t}$)	=	MAX (day-ahead import transaction quantity – pre-dispatch import transaction quantity, 0)
$DA_ISD_{k,h}^{i,t}$	=	MAX ($DA_DQSI_{k,h}^{i,t} – PD_DQSI_{k,h}^{i,t}$, 0) Where: $DA_DQSI_{k,h}^{i,t}$ is the *schedule of record* quantity scheduled for injection by *market participant* ‘k’ for an import transaction at *intertie metering point* ‘i’ during *metering interval* ‘t’ of *settlement hour* ‘h’; and $PD_DQSI_{k,h}^{i,t}$ is the pre-dispatch quantity scheduled for injection by *market participant* ‘k’ at *intertie metering point* ‘i’ during *metering interval* ‘t’ of *settlement hour* ‘h’

Let $XPD_BE_{k,h}^{i,t}$ be the function which calculates the area under the curve created by an n x 2 matrix (B) of offered *price-quantity pairs*:

$$\left[\sum_{n=p^*}^{s^*} P_n \times (Q_n - Q_{n-1})\right] + (Q - Q_{s^*}) \times P_{s^*+1}$$

where matrix (B) is *energy offers* submitted in pre-dispatch, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered price in each *price quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2

p* = the highest indexed row of matrix $XPD_BE_{k,h}^{i,t}$ such that $Q_{p^*} \leq PD_DQSI_{k,h}^{i,t} \leq Q_n$ and where $Q_{p^*-1} = PD_DQSI_{k,h}^{i,t}$ and where if $Q_{p^*} < Q_{p^*-1}$, let $Q_{p^*} = Q_{p^*-1}$

s* = the highest indexed row of matrix $XPD_BE_{k,h}^{i,t}$ such that $Q_{s^*} \leq DA_DQSI_{k,h}^{i,t} \leq Q_n$

Let $XDA_BE_{k,h}^{i,t}$ be the function which calculates the area under the curve created by an n x 2 matrix (B) of offered *price-quantity pairs*:

$$\left[\sum_{n=c^*}^{d^*} P_n \times (Q_n - Q_{n-1})\right] + (Q - Q_{d^*}) \times P_{d^*+1}$$

where matrix (B) is *energy offers* submitted in the *schedule of record*, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered price in each *price quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2

c* = the highest indexed row of matrix $XDA_BE_{k,h}^{i,t}$ such that $Q_{c^*} \leq PD_DQSI_{k,h}^{i,t} \leq Q_n$ and where $Q_{c^*-1} = PD_DQSI_{k,h}^{i,t}$ and where if $Q_{c^*} < Q_{c^*-1}$, let $Q_{c^*} = Q_{c^*-1}$

d* = the highest indexed row of matrix $XDA_BE_{k,h}^{i,t}$ such that $Q_{d^*} \leq DA_DQSI_{k,h}^{i,t} \leq Q_n$

Such that the day-ahead import failure charge for *market participant* 'k' during *settlement hour* 'h' for all *intertie metering points* 'i' may be formulated with the above components as follows:

$DA_IFC_{k,h}$ = For all *intertie metering points* and all *metering intervals* during the *settlement hour*:

-1 x MINIMUM of:

[MAXIMUM of:

[[The sum of all revenues implied by each import transaction valued at the *pre-dispatch energy market price* in the Ontario zone for the difference in quantity scheduled in pre-dispatch and the quantity scheduled in the *schedule of record*.

Minus:

Those costs represented through the *offers* for the import transaction scheduled in the *schedule of record*] or zero],

[MAXIMUM of:

[the pre-dispatch *offer* to increase quantity scheduled in pre-dispatch to quantity scheduled day-ahead minus the day-ahead *offer* to increase quantity scheduled in pre-dispatch to quantity scheduled in the *schedule of record*] or zero],

[day-ahead import scheduling deviation quantity times the MAXIMUM of (zero or the pre-dispatch *energy market price* in the Ontario zone)]]

$DA_IFC_{k,h}$ =

$$\sum_{LT}(-1)\times MIN\left[MAX\left(0,OP\left(PD_EMP_{h}^{m,t},DA_DQSI_{k,h}^{i,t},DA_BE_{k,h}^{i,t}\right)-OP\left(PD_EMP_{h}^{m,t},PD_DQSI_{k,h}^{i,t},DA_BE_{k,h}^{i,t}\right),\right.\right.$$
$$\left.\left.MAX\left(0,XPD_BE_{k,h}^{i,t}-XDA_BE_{k,h}^{i,t}\right),\left(MAX\left(0,PD_EMP_{h}^{m,t}\right)\times DA_ISD_{k,h}^{i,t}\right)\right]\right]$$

Where:

$DA_BE_{k,h}^{i,t}$ *are energy offers* submitted into the schedule of record, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered price in each *price-quantity pair* where offered prices are in column 1 and offered quantities are in column 2;

$PD_BE_{k,h}^{i,t}$ are *energy offers* submitted in pre-dispatch, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered price in each *price-quantity pair* where offered prices are in column 1 and offered quantities are in column 2;

$PD_EMP_{h}^{m,t}$is the $PD_EMP_{h}^{m,t}$;

'T' is the set of all *metering intervals* 't' in *settlement hour* 'h';

'I' is the set of all *intertie metering points* 'i'.

3.8C Real-Time Import and Real-Time Export Failure Charges

3.8C.1 The real-time import failure charge and the real-time export failure charges referred to in section 7.5.8B of Chapter 7 are *settlement amounts* that shall be determined in sections 3.8C.2 and 3.8C.3 and in sections 3.8C.4 and 3.8C.5 respectively.

Real-time Import Failure Charge

3.8C.2 The *IESO* shall assess a *market participant* with a real-time import failure charge for any quantity of *energy* scheduled for injection at an *intertie metering point* in the constrained *pre-dispatch schedule* where:

3.8C.2.1 the *market participant* fails either in whole or in part to schedule a *dispatch* quantity for injection in the constrained *real-time schedule* in the corresponding *metering interval* of the corresponding *settlement hour* at the same *intertie metering point*; and,

3.8C.2.2 the *IESO* has not determined, nor has the *market participant*-demonstrated to the satisfaction of the *IESO,* that the failure was due to bona fide and legitimate reasons as described in chapter 7, section 7.5.8B.

3.8C.3 For all import transactions scheduled in the constrained *pre-dispatch schedule* and meeting the criteria set out in section 3.8C.2, the real-time import failure charge shall be formulated as follows:

Let $RT_ISD_{k,h}^{i,t}$ be the real-time import scheduling deviation quantity calculated for *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h' as determined by the formula:

Real-time Import Scheduling Deviation Quantity	=	MAX (*pre-dispatch* import transaction quantity – real-time import transaction quantity, 0)
$RT_ISD_{k,h}^{i,t}$	=	MAX ($PD_DQSI_{k,h}^{i,t}$ - $DQSI_{k,h}^{i,t}$, 0)

such that the real-time import failure charge for *market participant* 'k' during *settlement hour* 'h' for all *intertie metering points* 'i' may be formulated with the above components as follows:

$RT_IFC_{k,h}$ = For all *intertie metering points*:

-1 x [MAXIMUM of:

[[The difference between: the real-time *energy market price* in the Ontario zone adjusted by the prevailing price bias adjustment factor for imports in effect for the *settlement hour* minus the *pre-dispatch* projected *energy market price* in the Ontario zone

times :

real-time import scheduling deviation quantity.]

or zero,]

subject to: a maximum value of the real-time import scheduling deviation quantity times the maximum of the real-time *energy market price* in the Ontario zone or zero]

$$RT_IFC_{k,h} = \sum^{I,T} (-1) \times MIN\left[MAX\left[0, (EMP_h^{m,t} + PB_IM_h^{t} - PD_EMP_h^{m,t}) \times RT_ISD_{k,h}^{i,t}\right], MAX(0, EMP_h^{m,t}) \times RT_ISD_{k,h}^{i,t}\right]$$

where:

$PD_EMP_h^{m,t}$ is the pre-dispatch projected *energy market price* applicable to all *delivery points* 'm' in the Ontario zone during *metering interval* 't' of *settlement hour* 'h';

$EMP_h^{m,t}$ is the real-time 5-minute *energy market price* applicable to all *delivery points* 'm' in the Ontario zone during *metering interval* 't' of *settlement hour* 'h';

$PB_IM_h^{t}$ is the price bias adjustment factor for import transactions in effect during *metering interval* 't' of *settlement hour* 'h';

'I' is the set of all *intertie metering points* 'i';

'T' is the set of all metering intervals in settlement hour 'h'.

Real-time Export Failure Charge

3.8C.4 The *IESO* shall assess a *market participant* with a real-time export failure charge for any quantity of *energy* scheduled for withdrawal at an *intertie metering point* in the constrained *pre-dispatch schedule* where:

3.8C.4.1 the *market participant* fails either in whole or in part to schedule a *dispatch* quantity for withdrawal in the constrained *real-time schedule* in

the corresponding *metering interval* of the corresponding *settlement hour* at the same *intertie metering point*; and,

3.8C.4.2 the *IESO* has not determined, nor has the *market participant* demonstrated to the satisfaction of the *IESO,* that the failure was due to bona fide and legitimate reasons described in chapter 7, section 7.5.8B.

3.8C.5 For all export transactions scheduled in the constrained *pre-dispatch schedule* and meeting the criteria set out in section 3.8C.4, the real-time export failure charge shall be formulated as follows:

Let $RT_ESD_{k,h}^{i,t}$ be the real-time export scheduling deviation quantity calculated for *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h' as determined by the formula:

Real-time Export Scheduling Deviation Quantity **=** MAX (*pre-dispatch* export transaction quantity – real-time export transaction quantity, 0)

$RT_ESD_{k,h}^{i,t}$ **=** $MAX (PD_DQSW_{k,h}^{i,t} - DQSW_{k,h}^{i,t}, 0)$

such that the real-time export failure charge for *market participant* 'k' during *settlement hour* 'h' for all *intertie metering points* 'i' may be formulated with the above components as follows:

$RT_EFC_{k,h}$ **=** For all *intertie metering points*:

-1 x [MAXIMUM of:

[[The difference between the *pre-dispatch* projected *energy market price* in the Ontario zone minus the real-time *energy market price* in the Ontario zone adjusted by the prevailing price bias adjustment factor for exports in effect for the *settlement hour*]

times :

real-time export scheduling deviation quantity.]

or zero,]

subject to: a maximum value of the:

real-time export scheduling deviation quantity times the maximum of the pre-dispatch *energy market price* in the Ontario zone or zero]

$$RT_EFC_{k,h} = \sum^{I,T}(-1)\times MIN\left[MAX\left[0,(PD_EMP_h^{m,t} - EMP_h^{m,t} - PB_EX_h^{t})\times RT_ESD_{k,h}^{i,t}\right], MAX(0,PD_EMP_h^{m,t})\times RT_ESD_{k,h}^{i,t}\right]$$

where:

$PD_EMP_h^{m,t}$ is the *pre-dispatch* projected *energy market price* applicable to all *delivery points* 'm' in the Ontario zone during *metering interval* 't' of *settlement hour* 'h'

$EMP_h^{m,t}$ is the real-time 5-minute *energy market price* applicable to all *delivery points* 'm' in the Ontario zone during *metering interval* 't' of *settlement hour* 'h'

$PB_EX_h^{t}$ is the price bias adjustment factor for export transactions in effect during *metering interval* 't' of *settlement hour* 'h'

'I' is the set of all *intertie metering points* 'i'

'T' is the set of all metering intervals in settlement hour 'h'

3.8C.6 Where any import transaction scheduled in the *pre-dispatch schedule of record* and subsequently scheduled at the same *intertie metering point* in the *real-time market* is subject to both the day ahead import failure charge of section 3.8B and the real-time import failure charge of section 3.8C, the *market participant* shall be assessed with the greater of these charges but not both.

3.8C.7 The *IESO* shall determine, in accordance with the applicable *market manual*, any applicable price bias adjustment factors to be used in the calculation of the real-time import failure charge and the real-time export failure charge. The price bias adjustment factor shall compensate for systematic differences between the pre-dispatch and real-time price.

3.8C.8 The *IESO* shall *publish* all applicable price bias adjustment factors in advance of the *settlement hours* to which such factors apply.

3.8C.9 [Intentionally left blank – section deleted]

3.8D Day Ahead Export Failure Charge

3.8D.1 The *IESO* shall apply the day-ahead export failure charge specified in section 3.8D.2 to a *market participant* for any quantity of *energy* scheduled for withdrawal at an *intertie metering point* scheduled in the *schedule of record*

where:

3.8D.1.1 the *market participant* fails either in whole or in part to schedule a *dispatch* quantity scheduled for withdrawal in the *pre-dispatch schedule* in the corresponding *metering interval* of the corresponding *settlement hour* at the same *intertie metering point;*

3.8D.1.2 the *IESO* has not determined, nor has the *market participant* demonstrated to the satisfaction of the *IESO,* that the failure is due to bona fide and legitimate reasons as described in chapter 7, section 7.5.8B; and

3.8D.1.3 the export transaction is not part of a day-ahead linked wheel.

3.8D.2 For all export transactions scheduled in the *schedule of record* and meeting the criteria of section 3.8D.1, the day-ahead export failure charge shall be formulated as follows:

Let OP(P,Q,B) be a profit function of Price (P), Quantity (Q) and an N by 2 matrix (B) of offered *price-quantity pairs*:

$$OP(P,Q,B) = P \cdot Q - \sum_{n=1}^{s^*} P_n \cdot (Q_n - Q_{n-1}) - (Q - Q_{s^*}) \cdot P_{s^*+1}$$

Using matrix notation for parameter 'B' this may be expressed as follows :

$$OP(P,Q,B) = P \cdot Q - \sum_{n=1}^{s^*} [B[n,1] \cdot (B[n,2] - B[n-1,2])] - [(Q - B[s^*,2]) \cdot B[s^*+1,1]]$$

Where:

s* is the highest indexed row of B such that $Q_{s^*} \le Q \le Q_n$ and where, $Q_0=0$

'P' is $PD_EMP_h^{m,t}$: *pre-dispatch* projected *energy market price* applicable to all *delivery* points 'm' in the Ontario zone in *metering interval* 't' of *settlement hour* 'h';

'Q' is $DA_ESD_{k,h}^{i,t}$ as defined below; and

'B' is $DA_BL_{k,h}^{i,t}$: *energy bids* submitted into the *schedule of record*, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered price in each *price quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2; or

'B' is $PD_BL_{k,h}^{i,t}$: *energy bids* submitted in pre-dispatch, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *delivery point* 'm' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered *price in e*ach *price quantity pair* where offered price*s 'P' are i*n column 1 and offered quantities 'Q' are in column 2

the *offer* matrix of *price-quantity pairs* for the applicable export transaction that was submitted by *market participant* 'k' and scheduled in the *schedule of record* during *metering interval* 't' for *settlement hour* 'h' of the *real-time trading day*

and,

Let $XDA_BL_{k,h}^{i,t}$ be the function which calculates the area under the curve created by an n x 2 matrix (B) of offered *price-quantity pairs*:

$$\sum_{n=c^*}^{d^*} P_n \times (Q_n - Q_{n-1}) + (Q - Q_{d^*}) \times P_{d^*+1}$$

where matrix (B) is *energy bids* submitted into the *schedule of record*, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered price in each *price quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2

c^*	=	the highest indexed row of matrix $XDA_BL_{k,h}^{i,t}$ such that $Q_{c^*} \leq PD_DQSW_{k,h}^{i,t} \leq Q_n$ and where $Q_{c^*-1} = PD_DQSW_{k,h}^{i,t}$ and where if $Q_{c^*} < Q_{c^*-1}$, let $Q_{c^*} = Q_{c^*-1}$
d^*	=	the highest indexed row of matrix $XDA_BL_{k,h}^{i,t}$ such that $Q_{d^*} \leq DA_DQSW_{k,h}^{i,t} \leq Q_n$

Let $XPD_BL_{k,h}^{i,t}$ be the function which calculates the area under the curve created by an n x 2 matrix (B) of offered *price-quantity pairs*:

$$\left[\sum_{n=p^*}^{s^*} P_i \times (Q_n - Q_{n-1})\right] + (Q - Q_{s^*}) \times P_{s^*+1}$$

where matrix (B) *energy bids* submitted in pre-dispatch, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered price in each *price quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2

p^* = the highest indexed row of matrix $XPD_BL_{k,h}^{i,t}$ such that $Q_{p^*} \leq PD_DQSW_{k,h}^{i,t} \leq Q_n$ and where $Q_{p^*-1} = PD_DQSW_{k,h}^{i,t}$ and where if $Q_{p^*} < Q_{p^*-1}$, let $Q_{p^*} = Q_{p^*-1}$

s^* = the highest indexed row of matrix $XPD_BL_{k,h}^{i,t}$ such that $Q_{s^*} \leq DA_DQSW_{k,h}^{i,t} \leq Q_n$

Such that the day-ahead export failure charge for *market participant* 'k' during *settlement hour* 'h' for all *intertie metering points* 'i' may be formulated with the above components as follows:

$DA_EFC_{k,h}$ = For all *intertie metering points* and all *metering intervals* during the *settlement hour*:

-1 x MINIMUM of:

[MAXIMUM of:

[-1 x [The sum of all revenues implied by each export transaction valued at the *pre-dispatch energy market price* in the Ontario zone for the difference in quantity scheduled in pre-dispatch and the quantity scheduled in the *schedule of record*.

Minus:

Those costs represented through the *offers* for the export transaction scheduled in the *schedule of record*]

or zero],

[MAXIMUM of:

[the day-ahead *bid* to increase quantity scheduled in pre-dispatch to quantity scheduled day-ahead minus the pre-dispatch *bid* to increase quantity scheduled in pre-

dispatch to quantity scheduled in the *schedule of record*]

or zero]

MAXIMUM of (zero or the day-ahead *bid* to increase quantity scheduled in pre-dispatch to quantity scheduled in the *schedule of record*)]

$DA_EFC_{k,h}$ =

$$\sum_{I,T}(-1)\times \mathrm{MIN}\Big[\mathrm{MAX}\Big(0,(-1)\times \mathrm{OP}\big(\mathrm{PD_EMP}_{h}^{m,t},\mathrm{DA_DQSW}_{k,h}^{i,t},\mathrm{DA_BL}_{k,h}^{i,t}\big)-(-1)\times \mathrm{OP}\big(\mathrm{PD_EMP}_{h}^{m,t},\mathrm{PD_DQSW}_{k,h}^{i,t},\mathrm{DA_BL}_{k,h}^{i,t}\big)\Big),\mathrm{MAX}\big(0,\mathrm{XDA_BL}_{k,h}^{i,t}-\mathrm{XPD_BL}_{k,h}^{i,t}\big),\mathrm{MAX}\big(0,\mathrm{XDA_BL}_{k,h}^{i,t}\big)\Big]$$

Where:

$DA_BL_{k,h}^{i,t}$ are energy bids submitted into the *schedule of record*, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered *price in e*ach *price quantity pair* where offered prices *'P' are i*n column 1 and offered quantities 'Q' are in column 2;

$PD_BL_{k,h}^{i,t}$ are *energy* bids submitted in pre-dispatch, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered *price in e*ach *price quantity pair* where offered prices *'P' are i*n column 1 and offered quantities 'Q' are in column 2;

$PD_EMP_{h}^{m,t}$ is the *pre-dispatch* projected *energy market price* applicable to all *delivery* points 'm' in the Ontario zone in *metering interval* 't' of *settlement hour* 'h';

'T' is the set of all *metering intervals* 't' in *settlement hour* 'h';

'I' is the set of all *intertie metering points* 'i'.

3.8E Day Ahead Linked Wheel Failure Charge

3.8E.1 The *IESO* shall apply the day-ahead linked wheel failure charge specified in section 3.8E.2 to a *market participant* for any quantity of *energy* scheduled for a linked wheel at an *intertie metering point* scheduled in the *schedule of record*

where:

3.8E.1.1 the *market participant* fails either in whole or in part to schedule a *dispatch* quantity scheduled for a linked wheel in the *pre-dispatch schedule* in the corresponding *metering interval* of the corresponding *settlement hour* at the same *intertie metering point;* and,

3.8E.1.2 the *IESO* has not determined, nor has the *market participant* demonstrated to the satisfaction of the *IESO,* that the failure is due to bona fide and legitimate reasons as described in chapter 7, section 7.5.8B.

3.8E.2 For all linked wheel transactions scheduled in the *schedule of record* and meeting the criteria of section 3.8E.1, the day-ahead linked wheel failure charge shall be formulated as follows:

Day-ahead linked wheel scheduling deviation ($DA_LWSD_{k,h}^{i,t}$)	=	MAX[(day-ahead import – hour-ahead pre-dispatch import), (day-ahead export – hour-ahead pre-dispatch export)]
$DA_LWSD_{k,h}^{i,t}$	=	$MAX[(DA_DQSI_{k,h}^{i,t} - PD_DQSI_{k,h}^{i,t}), (DA_DQSW_{k,h}^{i,t} - PD_DQSW_{k,h}^{i,t})]$ Where: $DA_DQSI_{k,h}^{i,t}$ is *schedule of record* quantity scheduled for injection by *market participant* 'k' at *delivery point* 'm' during *metering interval* 't' of *settlement hour* 'h'; $PD_DQSI_{k,h}^{i,t}$ is the *pre-dispatch* constrained quantity scheduled for injection by *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h'; $DA_DQSW_{k,h}^{i,t}$ is the *schedule of record* quantity scheduled for withdrawal by *market participant* 'k' at *delivery point* 'm' during *metering interval* 't' of *settlement hour* 'h'; and $PD_DQSW_{k,h}^{i,t}$ is the *pre-dispatch* constrained quantity scheduled for withdrawal by *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h'

Day-ahead price spread ($DA_PS_{k,h}^{i,t}$)	=	day-ahead constrained schedule *intertie* price of the sink for the export transaction minus day-ahead constrained *intertie* price of the source for the import transaction
$DA_PS_{k,h}^{i,t}$	=	$DA_ELMP_{k,h}^{m,t} – DA_ILMP_{k,h}^{m,t}$ Where: $DA_ELMP_h^{i,t}$ is the day-ahead constrained schedule *intertie* price at the *intertie metering point* 'i' of the sink for the export transaction during *metering interval* 't' of *settlement hour* 'h'; and $DA_ILMP_h^{i,t}$ is the day-ahead constrained *intertie* price at the *intertie metering point* 'i' of the source for the import transaction during *metering interval* 't' of *settlement hour* 'h'
Pre-dispatch price spread ($PD_PS_{k,h}^{i,t}$)	=	pre-dispatch constrained schedule *intertie* price of the sink for the export transaction – pre-dispatch constrained *intertie* price of the source for the import transaction
$PD_PS_{k,h}^{i,t}$	=	$PD_ELMP_h^{m,t} – PD_ILMP_h^{m,t}$ Where: $PD_ELMP_h^{i,t}$ is the *pre-dispatch* constrained schedule intertie price at the *intertie metering point* 'i' of the sink for the export transaction during *metering interval* 't' of *settlement hour* 'h'; and $PD_ILMP_h^{i,t}$ is the *pre-dispatch* constrained intertie price at the *intertie metering point* 'i' of the source for the import transaction during *metering interval* 't' of *settlement hour* 'h'

Such that the day-ahead linked wheel failure charge for *market participant* 'k' during *settlement hour* 'h' for all *intertie metering points* 'i' may be formulated with the above components as follows:

$DA_LWFC_{k,h}$	=	For all *intertie metering points* and all *metering intervals* during the *settlement hour*:

-1 x [The day-ahead linked wheel scheduling deviation quantity.

Multiplied by:

MAXIMUM of:

The day-ahead price spread less the pre-dispatch price spread or zero],

$$DA_LWFC_{k,h} = \sum_{I,T} (-1) \times \left[\left(DA_LWSD_{k,h}^{i,t} \right) \times MAX\left[0, \left(DA_PS_{k,h}^{i,t} - PD_PS_{k,h}^{i,t} \right) \right] \right]$$

Where:

'T' is the set of all *metering intervals* 't' in *settlement hour* 'h';

'I' is the set of all *intertie metering points* 'i'.

3.8E.3 If a day-ahead linked wheel failure charge specified in section 3.8E.2 applies to a linked wheel where a real-time import failure charge specified in section 3.8C.3 and/or a real-time export failure charge specified in section 3.8C.5 applies to the same linked wheel, a charge shall apply to the *market participant* equal to the lesser of:

3.8E.3.1 the day-ahead linked wheel failure charge specified in section 3.8E.2; and

3.8E.3.2 the sum of the real-time import failure charge and the real-time export failure charge, both subject to the scheduling deviation quantity between the *schedule of record* and the *pre-dispatch schedule*, as follows:

$RT_EFC_DALW_{k,h}^{i} + RT_IFC_DALW_{k,h}^{i}$

Where:

$RT_EFC_DALW_{k,h}^{i}$	=	real-time export failure charge for the export portion of the day-ahead linked wheel for the quantity failure from day-ahead to Pre-dispatch

$$RT_EFC_DALW_{k,h}^{i} = \sum^{T}(-1) \times \mathrm{MIN}\left[\mathrm{MAX}\left[0, \left(PD_EMP_{h}^{m,t} - EMP_{h}^{m,t} - PB_EX_{h}^{t}\right) \times \mathrm{MAX}\left(\left(DA_DQSW_{k,h}^{i,t} - PD_DQSW_{k,h}^{i,t}\right), 0\right)\right], \mathrm{MAX}\left(0, PD_EMP_{h}^{m,t}\right) \times \mathrm{MAX}\left(\left(DA_DQSW_{k,h}^{i,t} - PD_DQSW_{k,h}^{i,t}\right), 0\right)\right]$$

$RT_IFC_DALW_{k,h}^{i}$	=	real-time import failure charge for the import portion of the day-ahead linked wheel for the quantity failure from day-ahead to Pre-dispatch

$$RT_IFC_DALW_{k,h}^{i} = \sum^{T}(-1) \times \mathrm{MIN}\left[\mathrm{MAX}\left[0, \left(EMP_{h}^{m,t} + PB_IM_{h}^{t} - PD_EMP_{h}^{m,t}\right) \times \mathrm{MAX}\left(\left(DA_DQSI_{k,h}^{i,t} - PD_DQSI_{k,h}^{i,t}\right), 0\right)\right], \mathrm{MAX}\left(0, EMP_{h}^{m,t}\right) \times \mathrm{MAX}\left(\left(DA_DQSI_{k,h}^{i,t} - PD_DQSI_{k,h}^{i,t}\right), 0\right)\right]$$

3.8F Day-Ahead Generator Withdrawal Charge

3.8F.1 The *IESO* shall apply the day-ahead *generator* withdrawal charge specified in section 3.8F.2 to a *market participant* who was deemed to have accepted the day-ahead production cost guarantee in accordance with Section 5.8.4 of Chapter 7 for any quantity of *energy* scheduled for injection at a *metering point* scheduled in the *schedule of record* where:

3.8F.1.1 the *market participant* withdraws their commitment scheduled in the *schedule of record* in the corresponding *metering interval* of the corresponding *settlement hour* at the same *metering point;* and,

3.8F.1.2 the *IESO* has not determined, nor has the *market participant* demonstrated to the satisfaction of the *IESO,* that the failure is to prevent endangering the safety of any person, damage to equipment, or violation of any *applicable law*.

3.8F.2 The day-ahead *generator* withdrawal charge shall be formulated as follows:

If withdrawal notification is received at or 4 hours prior to the first withdrawal hour in real time (PD – 4), then the Withdrawal Charge is calculated as follows:

$$DA_GWC_{\underset{event}{k,start}} = MIN\left(0, \sum_{i=1}^{n}(-1)\times OP\left(MIN\left(PD_EMP_{h}^{m,t}, EMP_{h}^{m,t}\right), MLP_{k,h}^{m,t}, DA_BE_{k,h}^{m,t}\right)\right)$$

Where:

n = the set of all *metering intervals* ‘t’ in *settlement hour* ‘h’ for the total number of hours with a *schedule of record* that are withdrawn

start event = the set of hours with a contiguous *schedule of record*

If withdrawal notification is received later than PD-4 or if the *market participant* does not notify the *IESO* of their intent to withdraw and does not inject for the hours committed in the *schedule of record*, then the withdrawal charge is calculated as follows:

$$DA_GWC_{\underset{event}{k,start}} = MIN\left(0, \sum_{i=1}^{n}(-1)\times OP\left(EMP_{h}^{m,t}, MLP_{k,h}^{m,t}, DA_BE_{k,h}^{m,t}\right)\right)$$

Where:

n = the set of all *metering intervals* ‘t’ in *settlement hour* ‘h’ for the total number of hours with a *schedule of record* for the start event that are withdrawn

start event = the set of hours with a contiguous *schedule of record*

3.9 Hourly Uplift Settlement Amounts

3.9.1 The hourly *settlement amounts* defined by the preceding provisions of this section 3 will result in an hourly *settlement* deficit that shall be recovered from

market participants as a whole through the *hourly uplift*. The total *hourly uplift settlement amount* for *settlement hour* 'h' ("$HUSA_h$") shall be determined according to the following equation:

$$HUSA_h = \sum_K \left(NEMSC_{k,h} + ORSC_{k,h} + CMSC_{k,h} + RDSA_{k,h} + TRSC_{k,h} + IOG_{k,h}\right) + TCRF_{k,h} - \sum_K \left(\sum_R ORSSD_{k,r,h} + \sum_R ORSCB_{r,k,h} + DA_IFC_{k,h} + RT_IFC_{k,h} + DA_EFC_{k,h} + RT_EFC_{k,h} + DA_LWFC_{k,h}\right)$$

over all 'k' *market participants*

$NEMSC_{k,h}$ = net *energy market settlement* credit for *market participant* 'k' in *settlement hour* 'h'

$ORSC_{k,h}$ = *operating reserve market settlement* credit for *market participant* 'k' in *settlement hour* 'h'

$CMSC_{k,h}$ = congestion management *settlement* credit for *market participant* 'k' in *settlement hour* 'h'

$RDSA_{k,h}$ = ramp-down *settlement* amount for *market participant* 'k' in *settlement hour* 'h'

$TRSC_{k,h}$ = *transmission rights settlement* credit for *market participant* 'k' in *settlement hour* 'h'

$IOG_{k,h}$ = intertie offer guarantee settlement credit for the *market participant* 'k' in *settlement hour* 'h'

$DA_IFC_{k,h}$= day-ahead import failure charge for the *market participant* 'k' in *settlement hour* 'h'

$RT_IFC_{k,h}$ = real-time import failure charge for the *market participant* 'k' in *settlement hour* 'h'

$DA_EFC_{k,h}$= day-ahead export failure charge for the *market participant* 'k' in *settlement hour* 'h'

$RT_EFC_{k,h}$= real-time export failure charge for the *market participant* 'k' in *settlement hour* 'h'

$DA_LWFC_{k,h}$= day-ahead linked wheel failure charge for the *market participant* 'k' in *settlement hour* 'h'

$TCRF_{k,h}$ = transmission charge reduction fund contribution in *settlement hour* 'h'

$ORSSD_{k,r,h}$ = *operating reserve settlement* debit for *operating deviations* for *class r reserve* for *market participant* 'k' in *settlement hour* 'h'

$ORSCB_{r,k,h}$ = *operating reserve* non-accessibility charge for *class r reserve* for *market participant* 'k' in *settlement hour* 'h'

3.9.2 The *IESO* shall allocate *hourly uplift* on a pro-rata basis across all allocated quantities of *energy* withdrawn at all *RWMs* and at all *intertie metering points* during all *metering intervals* within each *settlement hour* in which an *hourly uplift settlement amount* accrues.

3.9.3 *Hourly uplift* and non-hourly *settlement amounts* shall be disaggregated on *settlement statements* in such manner as shall be determined by the *IESO.*

3.9.4 Until such time that the *IESO* has the software capability to include the following *settlement amounts*:

the day-ahead *intertie offer* guarantee *settlement* ($DA_IOG_{k,h}$)*;* or

the day-ahead import failure charge ($DA_IFC_{k,h}$),

in the *hourly uplift settlement amount,* the *IESO* shall recover or distribute such *settlement amounts* as non-hourly *settlement amounts* under the provisions of section 4.8.1 or 4.8.2 respectively commencing with the activation of the day-ahead commitment process.

3.9.5 Until such time that the *IESO* has the software capability to include the following *settlement amounts*:

the real-time import failure charge ($RT_IFC_{k,h}$)*;* or

the real-time export failure charge ($RT_EFC_{k,h}$),

in the *hourly uplift settlement amount,* the *IESO* shall recover or distribute such *settlement amounts* as non-hourly *settlement amounts* under the provisions of section 4.8.2.

4. Non-hourly Settlement Amounts

4.1 Transmission Tariff Charges

4.1.1 The *IESO* shall collect from *transmission customers*, and distribute to *transmitters*, *transmission services charges* approved by the *OEB* in accordance with Chapter 10.

4.2 Ancillary Service Payments

4.2.1 The *IESO* shall have the authority to negotiate *reliability must-run contracts* with *registered market participants* or prospective *registered market participants* regarding the operation of *reliability must-run resources* in accordance with section 9 of Chapter 7. Where such *reliability must-run contracts* provide both for payments from the *energy market* and *operating reserve market* pursuant to section 3 and additional payments for making *physical services*, other than *contracted ancillary services*, available to those markets, any such additional payments required to be made in a given *energy market billing period* shall be recovered from *market participants* through a uniform charge, in $/MWh, imposed on a pro-rata basis across all allocated quantities of *energy* withdrawn at all *RWMs* and at all *intertie metering points* during all *metering intervals* and *settlement hours* within that *energy market billing period*.

4.2.2 The *IESO* shall contract for *certified black start facilities* adequate to permit the *IESO* to meet its obligations under Chapter 5. The costs to the *IESO* of contracting for such *certified black start facilities* in a given *energy market billing period* shall be recovered from *market participants* through a uniform charge, in $/MWh, imposed on a pro-rata basis across all allocated quantities of *energy* withdrawn at all *RWMs* and at all *intertie metering points* during all *metering intervals* and *settlement hours* within that *energy market billing period*.

4.2.3 The *IESO* shall contract for *regulation* adequate to permit the *IESO* to meet its obligations under Chapter 5. The costs to the *IESO* of contracting for *regulation* in a given *energy market billing period* shall be recovered from *market participants* through a uniform charge, in $/MWh, imposed on a pro-rata basis across all allocated quantities of *energy* withdrawn at all *RWMs* and at all *intertie metering points* during all *metering intervals* and *settlement hours* within that *energy market billing period*.

4.2.3A [Intentionally left blank – section deleted]

4.2.4 The *IESO* shall contract for *reactive support service* and *voltage control service* adequate to permit the *IESO* to meet its obligations under Chapter 5. The costs to the *IESO* of contracting for such *reactive support service* and *voltage control service* in a given *energy market billing period* shall be recovered in accordance with the following:

4.2.4.1 *market participants* shall pay for such costs through a uniform charge, in $/MWh, imposed on a pro-rata basis across all allocated quantities of *energy* withdrawn at all *RWMs* and at all *intertie metering points* during all *metering intervals* and *settlement hours* within that *energy market billing period*;

4.2.4.2 there shall be no power factor requirements or penalties associated with electrical power flowing out of Ontario through *intertie metering points*; and

4.2.4.3 there shall be no separate compensation from the *IESO* for *reactive support service* and *voltage control service* from equipment such as capacitor banks, reactor banks, and synchronous condensers owned by *transmitters*. Any compensation for providing such *ancillary services* shall be included in the *transmission services charges* to the extent provided by the *OEB*.

4.2.5 Subject to sections 9.4.2 and 9.4.4 of Chapter 7, no compensation shall be paid for *ancillary services* provided pursuant to the *connection* requirements of Chapter 4.

4.2.6 [Intentionally left blank]

4.3 [Intentionally left blank]

4.4 [Intentionally left blank – section deleted]

4.4.1 [Intentionally left blank – section deleted]

4.5 IESO Administration Charge, Penalties, and Fines

4.5.1 The *IESO* shall determine a methodology for calculating and allocating an *IESO administration charge.*

4.5.2 [Intentionally left blank – section deleted]

4.6 [Intentionally left blank – section deleted]

4.6.1 [Intentionally left blank – section deleted]

4.7 TR Clearing Account Disbursements

4.7.1 Disbursements from the *TR clearing account* ordered by the *IESO Board* pursuant to section 4.18.2 of Chapter 8 shall be distributed among *market participants* based on the proportionate share of all *transmission service charges* paid during *energy market billing periods* immediately preceding the current *energy market billing period,* in accordance with this section 4.7.

4.7.1.1 The portion of the total disbursements from the *TR clearing* account allotted to *market participants* that have paid provincial transmission charges shall be disbursed to *market participants* on an individual basis as a non-hourly *settlement amount* according to each *market participant's* proportionate quantity of energy withdrawn from the *IESO-controlled grid* at all *RWMs* excluding *intertie metering points* during *energy market billing periods* immediately preceding the current *energy market billing period,* as determined by the *IESO Board,* in the manner described in sections 4.7.2 and 4.7.3.

4.7.1.2 The portion of the total disbursements from the *TR clearing account* allotted to *market participants* that have paid *export transmission service* charges shall be disbursed to *market participants* on an individual basis as a non-hourly *settlement amount* according to each *market participant's* proportionate quantity of *energy* withdrawn from the *IESO-controlled grid* at all *intertie metering points* during *energy market billing periods* immediately preceding the current *energy market billing period,* as determined by the *IESO Board,* in the manner described in sections 4.7.2 and 4.7.3.

4.7.2 The portion of any disbursement from the *TR clearing account* payable to *market participant* 'k' in the current *energy market billing period* shall be calculated as follows:

$$TRCAC_k = \frac{TRCAD}{\sum_{K,H}^{M,T} AQEW_{k,h}^{m,t}} \times \sum_{H}^{M,T} AQEW_{k,h}^{m,t}$$

For *market participants* that have paid provincial transmission service charges in the *energy market billing periods* immediately preceding the current *energy market billing period*, as determined by the *IESO Board*:

$$TRCAC_k = TRCAD_L \times \sum_H^{M,T} (AQEW_{k,h}^{m,t}) / \sum_{K,H}^{M,T} (AQEW_{k,h}^{m,t})$$

For *market participants* that have paid *export transmission service* charges in the *energy market billing periods* immediately preceding the current *energy market billing period*, as determined by the *IESO Board*:

$$TRCAC_k = TRCAD_E \times \sum_H {}^{I,T} [(SQEW_{k,h}{}^{i,t}) / \sum_{K,H} {}^{I,T} (SQEW_{k,h}{}^{i,t})]$$

Where:

$$TRCAD_L = (\sum_K TD_C / \sum_K TD_{C,C1}) \times TRCAD$$

$$TRCAD_E = (\sum_K TD_{C1} / \sum_K TD_{C,C1}) \times TRCAD$$

$TRCAC_k$ = the *TR clearing account* credit payable to *market participant* 'k' in the current *energy market billing period*

TRCAD = the total dollar value of all disbursements from the *TR clearing account* authorised by the *IESO Board* in the current *energy market billing period*

$TRCAD_L$ = the portion of the total dollar value of all disbursements from the *TR clearing account* authorized by the *IESO Board* in the current *energy market billing period* allocated to *market participants* that have paid provincial transmission service charges "C" in the *energy market billing periods* immediately preceding the current *energy market billing period*, as determined by the *IESO Board*

$TRCAD_E$ = the portion of the total dollar value of all disbursements from the *TR clearing account* authorized by the *IESO Board* in the *current energy market billing period* allocated to *market participants* that have paid *export transmission service* charges "C1" in the *energy market billing periods* immediately preceding the current *energy market billing period*, as determined by the *IESO Board*

M = the set of all *RWMs* 'm' excluding *intertie metering points* during *energy market billing periods* immediately preceding the current *energy market billing period*, as determined by the *IESO Board*

I = *intertie metering points* 'i' during *energy market billing periods* immediately preceding the current *energy market billing period*, as determined by the *IESO Board*

K = the set of all *market participants* 'k' during *energy market billing periods* immediately preceding the current *energy market billing period,* as determined by the *IESO Board*

T = the set of all *metering intervals* 't' in *energy market billing periods* immediately preceding the current *energy market billing period,* as determined by the *IESO Board*

H = the set of all *settlement hours* 'h' in *energy market billing periods* immediately preceding the current *energy market billing period,* as determined by the *IESO Board*

C = the set of all monthly service charge types 'c' as follows: 650,651,652

C1 = the set of all monthly export transmission charge types 'c' as follows: 653

4.7.3 Where a $TRCAC_k$ is payable to a former *market participant*, the *IESO* will endeavour to distribute the $TRCAC_k$ as specified in the applicable *market manual*. If the *IESO* cannot distribute a $TRCAC_k$ to a former *market participant* as specified in the applicable *market manual,* such amounts shall remain in the *TR clearing account* for subsequent debits in accordance with section 4.18.1 of Chapter 8.

4.7A [Intentionally left blank – section deleted]

4.7A.1 [Intentionally left blank – section deleted]

4.7A.1.1 [Intentionally left blank – section deleted]

4.7A.1.2 [Intentionally left blank – section deleted]

4.7A.2 [Intentionally left blank – section deleted]

4.7B Real-Time Generation Cost Guarantee Payments

4.7B.1 The *IESO* shall determine on a *per-start* basis, for each *generation facility* that has met the eligibility criteria for the real-time generation cost guarantee specified in sections 2.2B, 5.7 and 6.3A of Chapter 7, the following:

4.7B.1.1 the sum of the following revenues earned in each *dispatch interval* during the period from synchronization until the end of the *minimum generation block run-time* or the end of the *minimum run-time,* whichever comes first:

a. *energy market* prices multiplied by the sum of the applicable AQEI for *energy* injected up to and including the *minimum loading point*; and

b. any congestion management *settlement* credit payments resulting from the *facility* being constrained on in order to meet its *minimum loading point*.

4.7B.1.2 the applicable *combined guaranteed costs* for the specified submission to which the revenues determined in accordance with 4.7B.1.1 apply. Subject to section 4.7B.1.3, the *combined guaranteed costs* will be calculated by the *IESO* and will be the sum of the following costs:

4.7B.1.2A the submitted eligible costs, determined in accordance with section 4.7B.5 and section 2.2B.6 of Chapter 7, as applicable; and

4.7B.1.2B the *offer* price associated with the real-time *dispatch* multiplied by the *energy* injected, to a maximum of the *minimum loading point,* during the period from the beginning of the *minimum generation block run-time* until the earlier of:

- the end of the period representing *minimum generation block run-time*; or
- the end of the period representing *minimum run-time*.

4.7B.1.2.C [Intentionally left blank – section deleted]

4.7B.1.3 the elements of the *combined guaranteed costs* in section 4.7B.1.2A shall be deemed to be zero where a *market participant* is also eligible for the start-up cost component of a day-ahead production cost guarantee attributable to the same start-up event.

4.7B.2 If for each eligible *generation facility* the sum of the revenues calculated pursuant to section 4.7B.1.1 is greater than or equal to the *combined guaranteed costs* referred to in section 4.7B.1.2, then no additional payments are made in respect of the eligible *generation facility* by the *IESO.*

4.7B.3 If for each eligible *generation facility* the sum of the revenues calculated pursuant to section 4.7B.1.1 is less than the *combined guaranteed costs* referred to in section 4.7B.1.2, then the *IESO* shall calculate that difference and shall include that amount in the form of additional payments made in respect of the eligible *generation facility*.

4.7B.4 A *real-time* generation cost guarantee shall not be paid for a *generation unit* with respect to costs incurred or revenues accrued by that *generation unit* for which a day-ahead production cost guarantee applies under section 4.7D.

4.7B.4A A real-time generation cost guarantee shall not be paid where a *generation unit* has committed its *capacity* to an external *control area* and:

4.7B.4A.1 the external *control area operator* has called a *called capacity export* prior to the *generation unit* being scheduled for the real-time generation cost guarantee in accordance with section 5.7 of Chapter 7; or

4.7B.4A.2 the external *control area operator* has called a *called capacity export* after the *generation unit* has been scheduled for the real-time generation cost guarantee in accordance with section 5.7 of Chapter 7 and the *IESO* is restricting other transactions on *interconnected systems* in accordance with section 2.3 and 5.7 of Chapter 5, while maintaining the *called capacity export* transaction.

The *IESO* may withhold or recover such payments made in respect of the *generation unit* and shall redistribute any recovered payments in accordance with section 4.8.2.

Calculating Eligible Costs:

4.7B.5 The *IESO* shall calculate the submitted eligible costs described in section 2.2B.5 of Chapter 7, as follows and as further specified in the applicable *market manual*:

4.7B.5.1 The incremental fuel cost is equal to the fuel price multiplied by the fuel quantity where:

Fuel price =

- pre-approved price, adjusted by the applicable foreign exchange rate, if any; plus
- pre-approved services price adder; plus
- pre-approved cap and trade price adder, if applicable.

Fuel quantity =

- submitted *start volume*; plus

- submitted *start volume* multiplied by the pre-approved compressor volume adder fuel percentage, except for purposes of calculating cap and trade costs.

4.7B.5.2 The incremental operating and maintenance cost is equal to:

- electricity consumption cost, equal to the pre-approved electricity consumption price multiplied by the pre-approved electricity consumption quantity; plus
- pre-approved operating consumables cost adder; plus
- pre-approved planned maintenance cost adder, adjusted by the applicable foreign exchange rate, if any.

4.7C [Intentionally left blank – section deleted]

4.7C.1 [Intentionally left blank – section deleted]

4.7C.2 [Intentionally left blank – section deleted]

4.7C.3 [Intentionally left blank – section deleted]

4.7D Day-Ahead Production Cost Guarantee Payments

4.7D.1 The *IESO* shall determine on a *per-start* basis, for each *generation unit* that has met the criteria set out in chapter 7, sections 5.8.4, a day-ahead production costs guarantee consisting of the following components:

a. Component 1 is any shortfall in payment on the delivered real-time *dispatch* of the *schedule of record* and will be based upon the real-time revenue received for that amount of *energy* in comparison with the value as represented in the *generator's* day-ahead *offer* for incremental *energy* and *speed-no-load costs*;

b. Component 2 is the value of arranging the delivery (where the real-time *offer* is less than the day-ahead *offer*), or any gain (where the real-time *offer* is greater than the day-ahead *offer*)[2] for the portion of *schedule of record* quantity that is not implemented in the real-time *dispatch* schedule;

c. Component 3 is any income from real-time *energy* congestion management settlement credit (CMSC) included in a *generator's*

[2] Where the real-time *offer* is equal to the day-ahead *offer*, the value/gain is equal to zero (0).

schedule of record delivered in real-time and will be used to reduce the day-ahead production cost guarantee payment;

d. Component 4 is any income from real-time *operating reserve* in a *generator's schedule of record* that was not dispatched in real-time and will be used to reduce the day-ahead production cost guarantee payment; and

e. Component 5 is the as-offered *start-up cost* (as-offered value of bringing an off-line *generator* on-line to *minimum loading point*).

4.7D.2 The *IESO* shall determine the type of schedule and which components described in Section 4.7D.1 are included in the day-ahead production cost guarantee, for each *generation unit,* as follows:

a. Variant 1: If the *generation unit* is not operating from the previous *dispatch day* into the current *dispatch day*, the day-ahead production costs guarantee calculation for the current *dispatch day* includes Components 1 through 5. Variant 1 occurs when:

- the *generation unit* is not operating at the end of the previous DACP dispatch day (Day-1 HE 24 indicates off-line status); or
- the *generation unit* is operating at the end of the previous DACP dispatch day (Day-1, HE 24 indicates on-line status) but it is not operating into the current DACP dispatch day (Day 0, HE 1 indicates off-line status); or
- the *generation unit* is scheduled to start later in the current DACP dispatch day.

b. Variant 2: If the *generation unit* is operating from the previous *dispatch day* into the current *dispatch day*, to complete its *minimum generation block run-time* the day-ahead production costs guarantee calculation for the current *dispatch day* includes Components 1 through 4 but does not include Component 5. The day-ahead production costs guarantee calculation also includes a clawback for Component 1 and Component 3

c. Variant 3: If a *generation unit* is operating from the previous *dispatch day* into the current *dispatch day* and has completed its *minimum generation block run-time* in the previous *dispatch day*, the day-ahead production costs guarantee calculation for the current *dispatch day* includes Components 1 through 4 but does not include Component 5. Variant 3 occurs when:

- the *generation unit* is operating from the previous DACP *dispatch day* (Day-1, HE 24 indicates on-line status) into the current DACP *dispatch day* (Day 0, HE 1 indicates on-line status) and has completed its *MGBRT* in the previous DACP *dispatch day*; or
- the *generation unit* is operating from the previous DACP *dispatch day* (Day-1, HE 24 indicates on-line status) into the current DACP *dispatch day*, (Day 0, HE 1 indicates on-line status) and has not completed its *MGBRT* and is scheduled in the current DACP *dispatch day* for hours in excess of completing its *MGBRT* from the previous DACP *dispatch day*. Variant 3 in the current DACP *dispatch day* is only for the hours in excess of completing the *MGBRT* hours for the start from the previous DACP *dispatch day*.

4.7D.3 The *IESO* shall calculate the day-ahead production cost guarantee components 1 through 4 for each interval in the *schedule of record* where the *generator* is injecting into the *IESO-controlled grid*.

4.7D.4 The *IESO* shall calculate the day-ahead production cost guarantee components based on the type of schedule described in Section 4.7D.2 as follows:

Component 1 – Variants 1, 2 and 3

Component 1 includes any shortfall in payment for the minimum of the *generator's schedule of record*, real-time constrained schedule and the allocated quantity of *energy* injected based upon the real-time revenue received for that amount of *energy* in comparison with the costs as represented in the *generator's* day-ahead *offer*. Component 1 is calculated as follows:

$PCG_COMP1_{k,h}^{m,t}$ = All day-ahead costs excluding as-offered *start-up costs* for the minimum of the *generator's schedule of record*, real-time constrained scheduled and the allocated quantity of *energy* injected over the interval minus all real-time revenue received over the interval for that amount of *energy*

$$PCG_COMP1_CB_{k,h}^{m,t} = (-1)\times OP\left(EMP_{h}^{m,t}, MIN\left(AQEI_{k,h}^{m,t}, MLP_{k,h}^{m,t}\right), DA_BE^{m,t}\right) + \frac{DA_SNLC_{k,h}^{m}}{12}$$

Component 1 Clawback – Variant 2

Component 1 Clawback recovers the day-ahead production cost guarantee Component 1 paid up to the *minimum loading point* for the remaining hours of *MGBRT*. Component 1 Clawback– Variant 2 is calculated as follows:

$PCG_COMP1_CB_{k,h}^{m,t}$ = All day-ahead costs excluding as-offered *start-up costs* up to the minimum of the *generation facility's minimum loading point* and the allocated quantity of energy injected over the interval minus all real-time revenue received over the interval for that amount of *energy*

$$PCG_COMP1_CB_{k,h}^{m,t} = (-1)\times OP\left(EMP_{h}^{m,t}, MIN\left(AQEI_{k,h}^{m,t}, MLP_{k,h}^{m,t}\right), DA_BE^{m,t}\right) + \frac{DA_SNLC_{k,h}^{m}}{12}$$

Component 2 – Variants 1, 2 and 3

If, as a result of economic selection, a portion of the *schedule of record* is not implemented in the real-time *dispatch* schedule, the day-ahead production cost guarantee:

Guarantees the cost of arranging the delivery if the real-time *offer price* is less than the day-ahead *offer price*; or

Subtracts any gain where the real-time *offer price* is greater than the day-ahead *offer price*.

In the absence of a forced de-rating or a scheduled de-rating, if there are no real-time *energy offers* for any portion of the day-ahead constrained schedule, the real-time *energy offers* for that portion of *energy* will be set to MMCP (*Maximum Market Clearing Price*) for the purposes of calculating Component 2.

If the real-time *energy offers* for any portion of the day-ahead constrained schedule is below $0.00 $/MWh (i.e. negative), the real-time *energy offers* for that portion of *energy* will be set to $0.00 $/MWh for the purposes of calculating Component 2.

Component 2 is calculated as follows:

$PCG_COMP2_{k,h}^{m,t}$ = As-offered day-ahead costs excluding as-offered *start-up costs* for the difference between:

- the minimum of the *generator's schedule of record*, the de-rated value of the *generation facility* or the maximum of the real-time constrained schedule and the allocated quantity of *energy* injected; and
- the minimum of the *generator's schedule of record* and the de-rated value of the *generation facility*

over the interval minus all real-time *energy offers* (with a minimum limit of zero) over the interval for that amount of *energy*

$$PCG_COMP2_{k,h}^{m,t} = XDA_BE_{k,h}^{m,t} - MAX\left(0, XBE_{k,h}^{m,t}\right)$$

Where:

Let $XBE_{k,h}^{m,t}$ be the function which calculates the area under the curve created by an n x 2 matrix (B) of offered *price-quantity pairs*:

$$\left[\sum_{n=p^*}^{s^*} P_n \times \left(Q_n - Q_{n-1}\right)\right] + \left(Q - Q_{s^*}\right) \times P_{s^*+1}$$

where matrix (B) is *energy offers* submitted in real-time, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at m*etering point* 'm' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered price in each *price quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2

Let $XDA_BE_{k,h}^{m,t}$ be the function which calculates the area under the curve created by an n x 2 matrix (B) of offered *price-quantity pairs*:

$$\left[\sum_{n=c^*}^{d^*} P_n \times \left(Q_n - Q_{n-1}\right)\right] + \left(Q - Q_{d^*}\right) \times P_{d^*+1}$$

where matrix (B) is *energy offers* submitted in pre-dispatch, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *metering point* 'm' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered price in each *price quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2

c^* = the highest indexed row of matrix $XDA_BE_{k,h}^{m,t}$ such that $Q_{c^*} \leq \min[DA_DQSI_{k,h}^{m,t}, OPCAP_{k,h}^{m,t}, \max(DQSI_{k,h}^{m,t}, AQEI_{k,h}^{m,t})] \leq Q_n$ and where $Q_{c^*-1} = \min[DA_DQSI_{k,h}^{m,t}, OPCAP_{k,h}^{m,t}, \max(DQSI_{k,h}^{m,t}, AQEI_{k,h}^{m,t})]$ and where if $Q_{c^*} < Q_{c^*-1}$, let $Q_{c^*} = Q_{c^*-1}$

d^* = the highest indexed row of matrix $XDA_BE_{k,h}^{m,t}$ such that $Q_{d^*} \leq \min[DA_DQSI_{k,h}^{m,t}, OPCAP_{k,h}^{m,t}] \leq Q_n$

p^* = the highest indexed row of matrix $XBE_{k,h}^{m,t}$ such that $Q_{p^*} \leq \min[DA_DQSI_{k,h}^{m,t}, OPCAP_{k,h}^{m,t}, \max(DQSI_{k,h}^{m,t}, AQEI_{k,h}^{m,t})] \leq Q_n$ and where $Q_{p^*-1} = \min[DA_DQSI_{k,h}^{m,t}, OPCAP_{k,h}^{m,t}, \max(DQSI_{k,h}^{m,t}, AQEI_{k,h}^{m,t})]$ and where if $Q_{p^*} < Q_{p^*-1}$, let $Q_{p^*} = Q_{p^*-1}$

s^* = the highest indexed row of matrix $XBE_{k,h}^{m,t}$ such that $Q_{s^*} \leq \min[DA_DQSI_{k,h}^{m,t}, OPCAP_{k,h}^{m,t}] \leq Q_n$

Component 3 – Variants 1, 2 and 3

The day-ahead production cost guarantee payment for a *generator* will be reduced by the income received from real time congestion management settlement credits (CMSC) for the *generator's schedule of record* delivered in real-time.

The *generator's schedule of record* will be measured against both the real-time constrained schedule and the real-time unconstrained schedule to determine the amount of revenue from congestion management settlement credits that should be included in the day-ahead production cost guarantee calculation.

For any interval, there are six possible orderings of the amount of a *generation facility's* capacity that may be included in the *schedule of record*, the real-time constrained schedule and the real-time unconstrained schedule. The table below summarizes the six possible orderings and the inclusion of Component 3 in the day-ahead production cost guarantee calculation.

For the purposes of determining the applicable CMSC in Component 3, the o*ffer price* is subject to Section 3.5.6.

Table: Ordering of Generator's Capacity and Day-Ahead Production Cost Guarantee Component 3

Scenario	Ordering	Component 3 - CMSC Included?
1	DQSI >= MQSI >= DA_DQSI	N
2	MQSI >= DQSI >= DA_DQSI	N
3	DQSI > DA_DQSI > MQSI	Y (Partial CMSC)
4	MQSI > DA_DQSI > DQSI	Y (Partial CMSC)
5	DA_DQSI >= DQSI > MQSI	Y (All CMSC)
6	DA_DQSI >= MQSI > DQSI	Y (All CMSC)

Component 3 is calculated as follows :

$PCG_COMP3_{k,h}^{m,t}$ = Income received from real time congestion management *settlement* credits (CMSC) for the *generator's schedule of record* delivered in real-time over the interval

Component 3 is only calculated when:

- the real-time CMSC ($TD_{k,h,105}^{m,t}$) for the same interval is a value other than zero; and
- the mathematical sign of (DQSI-MQSI) is equal to the mathematical sign of (AQEI-MQSI).

Scenario 1

$PCG_COMP3_{k,h}^{m,t} = 0$

Scenario 2

$PCG_COMP3_{k,h}^{m,t} = 0$

Scenario 3

$$PCG_COMP3_{k,h}^{m,t} = \begin{array}{l} OP\left(EMP_h^{m,t}, MQSI_{k,h}^{m,t}, BE_{k,h}^{m,t}\right) \\ - MAX\left(OP\left(EMP_h^{m,t}, DA_DQSI_{k,h}^{m,t}, BE_{k,h}^{m,t}\right), OP\left(EMP_h^{m,t}, AQEI_{k,h}^{m,t}, BE_{k,h}^{m,t}\right)\right) \end{array}$$

Scenario 4

$$PCG_COMP3_{k,h}^{m,t} = \begin{array}{l} OP\left(EMP_h^{m,t}, DA_DQSI_{k,h}^{m,t}, BE_{k,h}^{m,t}\right) \\ - MAX\left(OP\left(EMP_h^{m,t}, DQSI_{k,h}^{m,t}, BE_{k,h}^{m,t}\right), OP\left(EMP_h^{m,t}, AQEI_{k,h}^{m,t}, BE_{k,h}^{m,t}\right)\right) \end{array}$$

Scenario 5

$PCG_COMP3_{k,h}^{m,t}$ = Congestion management *settlement* credit calculated as per Section 3.5.

Scenario 6

$PCG_COMP3_{k,h}^{m,t}$ = Congestion management *settlement* credit calculated as per Section 3.5.

Component 3 Clawback – Variant 2

Component 3 Clawback – Variant 2 recovers the congestion management *settlement* credits (CMSC) paid up to the *minimum loading point* for the remaining hours of MGBRT. Component 3 Clawback – Variant 2 is calculated as follows:

$PCG_COMP3_CB_{k,h}^{m,t}$	=	Income received from real time congestion management *settlement* credits (CMSC) from the minimum of *generation units minimum loading point* and the allocated quantity of energy injected to the real-time unconstrained schedule over the interval

Component 3 Clawback - Variant 2 is only calculated when:

- the *schedule of record* is not less than both the real-time constrained schedule and the real-time unconstrained schedule and the event is a constrained-on event (i.e. Scenarios 3 and 5);
- the *minimum loading point* is greater than the real-time unconstrained schedule; and
- Component 3 ($PCG_COMP3_{k,h}^{m,t}$) for the same interval is a value other than zero.

Scenario 1

$$PCG_COMP3_CB_{k,h}^{m,t} = 0$$

Scenario 2

$$PCG_COMP3_CB_{k,h}^{m,t} = 0$$

Scenario 3

In Scenario 3, the clawback ($PCG_COMP3_CB_{k,h}^{m,t}$) is only calculated when the *minimum loading point* is greater than the real-time unconstrained schedule.

$$PCG_COMP3_CB_{\substack{k,h \\ m,t}} = \begin{aligned} &MAX\left(OP\left(EMP_h^{m,t}, MLP_{k,h}^{m,t}, BE_{k,h}^{m,t}\right), OP\left(EMP_h^{m,t}, AQEI_{k,h}^{m,t}, BE_{k,h}^{m,t}\right)\right. \\ &\left. - OP\left(EMP_h^{m,t}, MQSI_{k,h}^{m,t}, BE_{k,h}^{m,t}\right)\right) \end{aligned}$$

Scenario 4

$$PCG_COMP3_CB_{k,h}^{m,t} = 0$$

Scenario 5

In Scenario 5, the clawback ($PCG_COMP3_CB_{k,h}^{m,t}$) is only calculated when the *minimum loading point* is greater than the real-time unconstrained schedule.

$$PCG_COMP3_CB_{k,h}^{m,t} = \begin{matrix} MAX\left(OP\left(EMP_h^{m,t}, MLP_{k,h}^{m,t}, BE_{k,h}^{m,t}\right), OP\left(EMP_h^{m,t}, AQEI_{k,h}^{m,t}, BE_{k,h}^{m,t}\right)\right) \\ - OP\left(EMP_h^{m,t}, MQSI_{k,h}^{m,t}, BE_{k,h}^{m,t}\right) \end{matrix}$$

Scenario 6

$$PCG_COMP3_CB_{k,h}^{m,t} = 0$$

Component 4 – Variants 1, 2 and 3

The day-ahead production cost guarantee payment for a *generator* will be reduced by the income received from real-time *operating reserve* for the *generator's schedule of record* not dispatched in real-time.

Component 4 is calculated as follows:

$PCG_COMP4_{k,h}^{m,t}$ = net income received from real-time *operating reserve* over the interval for the *generator's schedule of record* not dispatched in real-time

$$PCG_COMP4_{k,h}^{m,t} = \begin{matrix} OP\left(PROR_{r1,h}^{m,t}, 30R_SQROR_{r1,k,h}^{m,t}, BR_{k,h}^{m,t}\right) \\ + OP\left(PROR_{r2,h}^{m,t}, 10NS_SQROR_{r2,k,h}^{m,t}, BR_{k,h}^{m,t}\right) \\ + OP\left(PROR_{r3,h}^{m,t}, 10S_SQROR_{r3,k,h}^{m,t}, BR_{k,h}^{m,t}\right) \end{matrix}$$

Where:

r1 = *30-minute operating reserve*

r*2* = 10-minute non-spinning *operating reserve*

r*3* = 10-minute spinning *operating reserve*

$$30R_SQROR_{r1,k,h}^{m,t} = MAX\left[0, MIN\left(DA_DQSI_{k,h}^{m,t} - MQSI_{k,h}^{m,t}, SQROR_{r1,k,h}^{m,t}\right)\right]$$

$$10NS_SQROR_{r2,k,h}^{m,t} = \begin{matrix} MAX\left[0, MIN\left(DA_DQSI_{k,h}^{m,t} - MQSI_{k,h}^{m,t} - \right.\right. \\ \left.\left. 30R_SQROR_{r1,k,h}^{m,t}, SQROR_{r2,k,h}^{m,t}\right)\right] \end{matrix}$$

$$10S_SQROR_{r3,k,h}^{m,t} = MAX\left[0,MIN\left(DA_DQSI_{k,h}^{m,t}-MQSI_{k,h}^{m,t}-30R_SQROR_{r1,k,h}^{m,t} -10NS_SQROR_{r2,k,h}^{m,t},SQROR_{r3,k,h}^{m,t}\right)\right]$$

x^* = the highest indexed row of matrix $BR_{r1,k,h}^{m,t}$, such that $QR_{x^*} \leq \max[0,\min(DA_DQSI_{k,h}^{m,t} - MQSI_{k,h}^{m,t}, SQROR_{r1,k,h}^{m,t})] \leq QR_n$ and where $QR_0 = 0$

y^* = the highest indexed row of matrix $BR_{r2,k,h}^{m,t}$ such that $QR_{y^*} \leq \max[0,\min(DA_DQSI_{k,h}^{m,t} - MQSI_{k,h}^{m,t} - 30R_SQROR_{r1,k,h}^{m,t}, SQROR_{r2,k,h}^{m,t})] \leq QR_n$ and where $QR_0 = 0$

z^* = the highest indexed row of matrix $BR_{r3,k,h}^{m,t}$, such that $QR_{z^*} \leq \max[0,\min(DA_DQSI_{k,h}^{m,t} - MQSI_{k,h}^{m,t} - 30R_SQROR_{r1,k,h}^{m,t} - 10NS_SQROR_{r1,k,h}^{m,t}, SQROR_{r3,k,h}^{m,t})] \leq QR_n$ and where $QR_0 = 0$

Component 5 – Variant 1

Component 5 is the as-offered *start-up cost* incurred to bring an off-line *generation unit* through all the unit specific start-up procedures, including synchronization and ramp up to *minimum loading point*. Component 5 is calculated as follows:

$PCG_COMP5_{k,h}^{m,t}$ = As-offered *start-up cost* submitted by the *market participant* for the DACP start event.

The rules for calculating Component 5 are as follows:

- **Scenario 1:** If the *market participant* achieves *minimum loading point* within the first 6 intervals[3] of the start of the DACP scheduled period, the full as-offered start-up cost is considered.
- **Scenario 2:** If the *generation unit* achieves *minimum loading point* between the start of the 7th interval and before the start of the 18th interval of the start of the DACP scheduled period, the as-offered start-up cost is calculated on a fractional basis. The as-offered start-up cost is calculated based on the number of 5-minute intervals the resource takes to achieve *minimum loading point* between the start of the 7th interval and before the start of the 18th interval.
- **Scenario 3:** If the *generation unit* achieves *minimum loading point* after the 17th interval of the start of the DACP scheduled period (i.e. 18th interval and onwards), the as-offered *start-up cost* is not considered.

[3] The duration of an interval is 5 minutes.

Scenario 1

$PCG_COMP5_{k,h}^{m,t} = DA_SUC_{k,h}^{m}$

Scenario 2

$$PCG_COMP5_{k,h}^{m,t} = DA_SUC_{k,h}^{m} - \left(DA_SUC_{k,h}^{m} \times \frac{1}{DA_INT} \times SUC_INT\right)$$

Where

DA_INT = 12

SUC_INT = number of 5-minute intervals between Interval 7 and 18 the *market participant* takes to achieve *minimum loading point*.

Scenario 3

$PCG_COMP5_{k,h}^{m,t} = 0$

Component 5 – Variants 2 and 3

Component 5 is not calculated for Variants 2 and 3.

4.7D.5 If for each DACP start event for each eligible *generation unit* the sum of the revenues referred to in section 4.7D.4 is greater than or equal to the sum of the costs referred to in section 4.7D.4, then the *IESO* shall make no additional payments in respect of the eligible *generation facility*.

4.7D.6 Subject to section 4.7D.7, if for each DACP start event for each eligible *generation unit* the sum of the revenues referred to in section 4.7D.4 is less than the sum of the costs referred to in section 4.7D.4, then the *IESO* shall include that amount in the form of additional payments made in respect of the eligible *generation facility*.

4.7D.7 A *generation unit* shall not be eligible for additional payments determined in accordance with section 4.7D.6 when:

- the *generation unit's* online status in Day-1, HE24 is attributed to any *pre-dispatch schedule* other than a *schedule of record;* and
- the *generation unit* receives a Variant 3 type *schedule of record* beginning in Day0, HE1 pursuant to section 4.7D.2.c for the purpose of ramping down the *generation unit* to offline status; and
- the *generation unit* would have otherwise not been economic in HE1 of Day 0.

The *IESO* may withhold or recover such payments made in respect of the *generation unit* and shall redistribute any recovered payments in accordance with section 4.8.2.

4.7D.8 A day-ahead production cost guarantee shall not be paid where a *generation unit* has committed its capacity to an external *control area* and:

4.7D.8.1 the external *control area operator* has called a *called capacity export* prior to the *generation unit* being scheduled for the day-ahead production cost guarantee in accordance with section 5.8 of Chapter 7; or

4.7D.8.2 the external *control area operator* has called a *called capacity export* after the *generation unit* has been scheduled for the day-ahead production cost guarantee in accordance with section 5.8 of Chapter 7 and the *IESO* is restricting other transactions on *interconnected systems* in accordance with section 2.3 and 5.7 of Chapter 5, while maintaining the *called capacity export* transaction.

The *IESO* may withhold or recover such payments made in respect of the *generation unit* and shall redistribute any recovered payments in accordance with section 4.8.2.

4.7E Day-Ahead Fuel Cost Compensation Settlement Amount

4.7E.1 In the event that the *IESO*, in order to maintain reliable operation of the *IESO-controlled grid* requires a *generation facility*:

a. that was included in the *schedule of record*; and

b. for which the *registered market participant* for the *generation facility* is deemed to have accepted the day-ahead production cost guarantee in accordance with Section 5.8.4 of Chapter 7;

either to de-synchronize from the *IESO-controlled grid* prior to the end of its commitment scheduled in the ***s****chedule of record* or not to synchronize to the *IESO-controlled grid*, the *market participant* may, in accordance with chapter 7 section 6.3B, claim, in the manner specified in the applicable *market manual*, reimbursement of financial losses related to the procurement of fuel for operation at its commitment scheduled in the *schedule of record* and which was not ultimately utilized by that *generation facility*.

4.7E.2 Where the *IESO* determines that claims made under section 4.7E.1 are valid, such compensation claims will be applied to the *market participant's settlement statement* for the last *trading day* of each *real-time market billing period* after the determination has been made.

4.7E.3 All claims made to the *IESO* pursuant to section 4.7E.1 may be subject to audit by the *IESO* which may obligate the *market participant* to demonstrate or otherwise make a binding declaration that the financial loss being claimed was not mitigated through the actions of:

a. the *market participant*;

b. an *affiliate* or subsidiary of the *market participant*; or

c. any other party that may have a commercial relationship with the *market participant* where that commercial relationship involves compensation of any kind that is directly related to the mitigation of the financial loss being claimed.

4.7E.4 The cumulative *settlement amounts* payable to *market participants* for each real-time *energy market billing period* under the provisions of section 4.7E.2 shall be recovered from *market participants* in accordance with section 4.8.1.12.

4.7F [Intentionally left blank – section deleted]

4.7F.1 [Intentionally left blank – section deleted]

4.7F.2 [Intentionally left blank – section deleted]

4.7F.3 [Intentionally left blank – section deleted]

4.7G Forecasting for Variable Generation

4.7G.1 The *IESO* may contract for forecasting services relating to *variable generation*.

4.7H [Intentionally left blank – section deleted]

4.7H.1 [Intentionally left blank – section deleted]

4.7H.2 [Intentionally left blank – section deleted]

4.7H.3 [Intentionally left blank – section deleted]

4.7I [Intentionally left blank – section deleted]

4.7I.1 [Intentionally left blank – section deleted]

4.7I.2 [Intentionally left blank – section deleted]

4.7I.3 [Intentionally left blank – section deleted]

4.7J Capacity Obligations

Capacity Obligation Availability Payments

4.7J.1 The *capacity auction* availability payment *settlement amount* for *capacity market participant* 'k' at *delivery point* or *intertie metering point* 'm' for the relevant *energy market billing period* ("$CAAP^m_k$") shall be calculated for each *energy market billing period* and disbursed to *capacity market participants* who have a *capacity obligation* during the relevant *obligation period* and which shall be calculated as follows:

$$CAAP^m_k = \Sigma^H CCO^m_{k,h} \times CACP^z_h$$

Where:

(a) 'H' is the set of all *settlement hours* within the *availability window* of all *business days* in the relevant *energy market billing period*.

4.7J.2 [Intentionally left blank – section deleted]

Capacity Obligation Availability Charges

4.7J.2.1 The *capacity auction* availability charge *settlement amount* for *capacity market participant* 'k' at *delivery point* or *intertie metering point* 'm' for the relevant *trading day* ("$CAAC^m_k$") shall be collected from such *capacity market participants* in accordance with the following:

4.7J.2.1A In regards to a *capacity market participant* participating with an *hourly demand response resource* or a *capacity dispatchable load resource*, the *capacity auction* availability charge *settlement amount* shall be calculated for each *trading day* for which it receives a standby notice and it fails for any *settlement hour* of the *availability window* during such *trading day* to submit a *demand response energy bid* in an amount that is greater than or equal to its *capacity obligation* in the day-ahead commitment process and maintain such *energy bid* through the *real-time energy market.* The *capacity auction* availability charge *settlement amount* is calculated as follows:

$$CAAC^{m}_{k} = \Sigma^{H} (-1) \times Max(0, CCO^{m}_{k,h} - DREBQ^{m}_{k,h}) \times CACP^{z}_{h} \times CNPF_{tm}$$

Where:

(a) 'H' is the set of all *settlement hours* within the *availability window* during the relevant *trading day*;

(b) If the *capacity market participant* did not submit a *demand response energy bid* for its *hourly demand response resource* or *capacity dispatchable load resource*, as the case may be, for *settlement hour* 'h' in the day-ahead commitment process or failed to maintain such *energy bid* through the *real-time energy market*, $DREBQ^{m}_{k,h} = 0$;

(c) In regards to *hourly demand response resource*, if the *demand response energy bids* submitted for *settlement hour* 'h' does not form part of *energy bids* spanning at least four consecutive *settlement hours*, $DREBQ^{m}_{k,h} = 0$;

(d) If the *demand response energy bid* submitted in the day-ahead commitment process for *settlement hour* 'h' is not equal to the *demand response energy bid* submitted in the *real-time market* for the same *settlement hour*, $DREBQ^{m}_{k,h}$ shall be equal to the lesser of the two *demand response energy bids*; and

(e) Notwithstanding any of the foregoing, $DREBQ^{m}_{k,h}$ shall not exceed the $CARC^{m}_{k}$ for the *hourly demand response resource* or *capacity dispatchable load resource*, as the case may be.

4.7J.2.1B For a *capacity market participant* participating with a *capacity generation resource*, *system-backed capacity import resource*, *generator-backed capacity import resource*, or *capacity storage resource*, the *capacity auction* availability charge *settlement amount* shall be calculated for each *trading day* it fails for any *settlement hour* of an *availability window* during such *trading day* to submit *energy offer* in an amount that is greater than or equal to its *capacity obligation* in the day-ahead commitment process and maintain such *energy offer* in accordance with the applicable *market manual*. The *capacity*

auction availability charge *settlement amount* is calculated as follows:

$$CAAC^{m}_{k} = \Sigma^{H} (-1) \times Max(0, CCO^{m}_{k,h} - CAEO^{m}_{h,k}) \times CACP^{z}_{h} \times CNPF_{tm}$$

Where:

(a) 'H' is the set of all *settlement hours* within the *availability window* during the relevant *trading day*;

(b) If the *capacity market participant* did not submit an *energy offer* in the day-ahead commitment process or maintain such *energy offer* in accordance with the applicable *market manual* for *settlement hour* 'h', $CAEO^{m}_{h,k} = 0$;

(c) If the *energy offer* submitted in the day-ahead commitment process for *settlement hour* 'h' is not equal to the *energy offers* submitted in *pre-dispatch* or the *real-time market* for the same *settlement hour*, the $CAEO^{m}_{h,k}$ shall be equal to the lesser of any such *energy offers*; and

(d) If a *capacity storage resource* receives a non-zero *energy dispatch instruction* within the relevant *availability window,* the $CAEO^{m}_{h,k}$ for the remaining *settlement hours* of the *availability window* after receiving such non-zero *energy dispatch instruction* shall be equal to the *energy offer* applicable to the *settlement hour* in which they receive such non-zero *energy dispatch instruction.*

Capacity Obligation Dispatch Charges

4.7J.2.2 Subject to section 19.4.5 and 7.5.3 of Chapter 7, the *capacity auction* dispatch charge *settlement amount* for *capacity market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' ("$CADC^{m}_{k,h}$") shall be calculated and collected from such *capacity market participant* participating with a commercial or industrial *hourly demand response resource* for each *settlement hour* of an *availability window* in which the *hourly demand response resource* fails to comply with an activation notice, as determined in accordance with section 4.7J.2.2.1, and which shall be calculated in accordance with the following:

$$CADC^{m}_{k,h} = (-1) \times DRSQty^{m}_{k,h} \times CACP^{z}_{h} \times CNPF_{tm}$$

Where:

(a) 'h' is a *settlement hour* in which the *hourly demand response resource* failed to comply with its activation notice, as determined in accordance with the applicable *market manual*.

(b) 'tm' is the *energy market billing period* that corresponds to *settlement hour* 'h'.

4.7J.2.2.1 A commercial or industrial *hourly demand response resource* is determined to have failed to comply with an activation notice if the following condition is true:

$$C\&I_HDR_BL^{m,t}_{k,h} - HDR_AC^{m,t}_{k,h} < 85\% \times (TBQ^{m,t}_{k,h} - DQSW_{k,h}{}^{m,t})$$

Where:

(a) "$C\&I_HDR_BL^{m,t}_{k,h}$" is the amount calculated pursuant to the applicable *market manual*.

(b) "$HDR_AC^{m,t}_{k,h}$" is the total measured quantity of *energy* consumed (in MWh) for *capacity market participant* 'k' at *delivery point* 'm' for the *hourly demand response resource* in *metering interval* 't' of *settlement hour* "h", as determined in accordance with the submitted measurement data and AQEW, as the case may be.

(c) "$TBQ^{m,t}_{k,h}$" has the same meaning as ascribed to the same variable within the definition of $HDRDC^{m}_{k,h}$ in section 3.1.10.

Capacity Obligation Administration Charges

4.7J.2.3 The *capacity auction* administration charge *settlement amount* for *capacity market participant* 'k' at *delivery point* 'm' in the relevant *energy market billing period* ("$CAADM^{m}_{k}$") shall be calculated and collected from each *capacity market participant* participating with a virtual *hourly demand response resource* or a *generator-backed capacity import resource* for each *energy market billing period* in

which such *capacity market participant* fails to provide timely, accurate and complete data, including measurement data to the *IESO* in accordance with the applicable *market manual*, and which shall be calculated as follows:

$$CAADM^{m}_{k} = (-1) \times CAAP^{m}_{k}$$

Where:

(a) '$CAAP^{m}_{k}$' is the *capacity auction* availability payment *settlement amount*, calculated in accordance with section 4.7J.1, for *capacity market participant* 'k' at *delivery point* or *intertie metering point* 'm' for the relevant *energy market billing period*.

Capacity Obligation Capacity Charges

4.7J.2.4 The *capacity auction* capacity charge *settlement amount* for *capacity market participant* 'k' at *delivery point* or *intertie metering point* 'm' in the relevant *energy market billing period* ("$CACC^{m}_{k}$") shall be calculated and collected from each *capacity market participant* for each *energy market billing period* in which such *capacity market participant* fails to deliver its *cleared ICAP* within the applicable threshold, as set out in the applicable *market manual,* in response to a *capacity auction capacity test*, and which shall be calculated as follows:

$$CACC^{m}_{k} = (-1) \times CAAP^{m}_{k}$$

Where:

(a) '$CAAP^{m}_{k}$' is the *capacity auction* availability payment *settlement amount*, calculated in accordance with section 4.7J.1, for *capacity market participant* 'k' at *delivery point* or *intertie metering point* 'm' for the relevant *energy market billing period*.

4.7J.2.5 [Intentionally left blank – section deleted]

4.7J.2.6 [Intentionally left blank – section deleted]

Capacity Obligation Capacity Import Call Failure Charges

4.7J.2.7 Subject to section 7.5.8A of Chapter 7, the *capacity auction* capacity import failure *settlement amount* for *capacity market participant* 'k' participating with a *generator-backed capacity import resource* at *delivery point* or *intertie metering point* 'm' for the relevant *energy market billing period* ("$CACIF^m_k$") shall be calculated and collected from such *capacity market participant* for each *energy market billing period* in which such *capacity market participant* fails to satisfy its *capacity obligation* in response to a *capacity import call*, as determined in accordance with the applicable *market manual*, and which shall be calculated as follows:

$$CACIF^m_k = (-1) \times CAAP^m_k$$

Where:

(a) '$CAAP^m_k$' is the *capacity auction* availability payment *settlement amount*, calculated in accordance with section 4.7J.1, for *capacity market participant* 'k' at *delivery point* or *intertie metering point* 'm' for the relevant *energy market billing period*.

Capacity Obligation Capacity Deficiency Charges

4.7J.2.8 The *capacity auction* capacity deficiency *settlement amount* for *capacity market participant* 'k' at *intertie metering point* 'i' for the relevant *energy market billing period* ("$CACD^i_k$") shall be calculated and collected from such *capacity market participant* for each *energy market billing period* in which the *IESO* has determined that all or a portion of the *capacity market participant's capacity obligation* is *over committed capacity*, and which shall be calculated and collected for the entire *obligation period* in accordance with the following:

$$CACD^i_k = \sum^H (-1.5) \times OCMW^i_k \times CACP^z_h$$

Where:

(a) 'H' is the set of all *settlement hours* within the *availability window* of all *trading days* within the relevant *energy market billing period*.

4.7J.2.8.1 If the *IESO* determines that all or a portion of the *capacity market participant's capacity obligation* is *over committed*

capacity, the *capacity market participant's capacity obligation* shall be reduced by the amount of *over committed capacity* effective as of the first *trading day* of the subsequent *energy market billing period*. If such reduction in the *capacity market participant's capacity obligation* for such resource results in such *capacity obligation* being less than one MW, the remainder of the *capacity market participant's capacity obligation* for such resource is forfeited effective as of the first *trading day* of the subsequent *energy market billing period*.

Capacity Obligation In-Period Cleared UCAP Adjustment Charge

4.7J.2.9 The *capacity obligation* in-period *cleared UCAP* adjustment charge *settlement amount* for *capacity market participant* 'k' at *delivery point* 'm' in the relevant *energy market billing period* ("$CAIPA^{m}_{k}$") shall be calculated and collected from such *capacity market participant* for i) the *energy market billing period* in which the *IESO* provided notice to the *capacity market participant* that the *hourly demand response resource's* average hourly capacity delivered over the four hour testing period was less than 90% of its *cleared UCAP*; ii) each prior *energy market billing period* of the relevant *obligation period* included as an adjustment to the next scheduled *recalculated settlement statement* for such *energy market billing period*; and iii) if the *capacity market participant* has filed a *notice of disagreement* in regards to the outcome of a *capacity auction capacity test,* each subsequent *energy market billing period* of the relevant *obligation period*. The *capacity obligation* in-period UCAP adjustment charge *settlement amount* is calculated as follows:

$$CAIPA^{m}_{k} = (-1 \times \text{Max}\ (0, (CAAP^{m}_{k} \times (\text{UCAP Adjustment}) + \sum^{H} CAAC^{m}_{k,h}))$$

Where:

(a) $CAAP^{m}_{k}$ is the *capacity obligation* availability payment *settlement amount* for *capacity market participant* 'k' at *delivery point* 'm' for the relevant *energy market billing period*, as calculated pursuant to section 4.7J.1.

(b) $CAAC^{m}_{k,h}$ is the *capacity obligation* availability charge *settlement amount* for *capacity market participant* 'k' at *delivery point* 'm' for *settlement hour* 'h', as calculated pursuant to section 4.7J.2.1.

(c) 'H' is the set of all *settlement hours* 'h' within the *availability window* of the relevant *energy market billing period.*

(d) 'UCAP Adjustment' is a de-rate (in %) based on the *hourly demand response resource's* delivered performance during a *capacity auction capacity test*, as determined in accordance with the applicable *market manual*. If the *capacity market participant* has filed a *notice of disagreement* in regards to the outcomes of the *capacity auction capacity test* in accordance with section 6.8, and but for filing such *notice of disagreement* the *capacity market participant* would have forfeited any of its *capacity obligation* pursuant to section 19.4.18 of Chapter 7, then the UCAP Adjustment shall equal 100%.

Capacity Obligation Buy-Out Charges

4.7J.3 A *capacity market participant* or a *capacity auction participant* may elect to be subject to a *capacity obligation* buy-out charge *settlement amount* for all, or a portion of, their *capacity obligation* in accordance with the applicable *market manual*. Upon the *IESO's* acceptance of a buy-out request, the *capacity market participant's capacity obligation* shall be reduced to reflect the approved buy-out and the *IESO* shall calculate the *capacity obligation* buy-out *settlement amount* for such *capacity market participant* 'k' at *delivery point* or *intertie metering point* 'm' ("$CABOC^{m}_{k}$") which shall be calculated as follows:

$$CABOC^{m}_{k} = 50\% \times \Sigma^{H} CBOC^{m}_{k} \times CACP^{z}_{h} \times (1 - CNPF_{tm})$$

Where:

(a) 'H' is the set of all *settlement hours* within the *availability window* of all *trading days* from the buy-out effective date to the end of the *commitment period*.

(b) 'tm' is the *energy market billing period* that corresponds to the relevant *settlement hour*.

Measurement Data Audit

4.7J.4 At any time, the *IESO* may audit any submitted measurement data and supporting information and a *capacity market participant* shall provide such information in the time and manner specified by the *IESO*. If, as a result of such an audit, the *IESO* determines that actual measurement data and supporting information differed from the submitted measurement data and supporting information, the

IESO shall recover from or distribute to a *capacity market participant* any resulting over or under payment, as applicable.

Capacity Obligation Dispatch Test Activation and Capacity Obligation Emergency Activation Payment

4.7J.5 Subject to section 4.7J.5.3, the *IESO* shall calculate and disburse a *capacity auction dispatch test* payment *settlement amount* or *capacity auction* emergency activation payment *settlement amount* for a valid *capacity auction dispatch test* or emergency activation, respectively, of an *hourly demand response resource* to the applicable *capacity market participant*, in accordance with the following:

4.7J.5.1 in regards to *capacity auction dispatch tests*, the c*apacity auction dispatch test* payment *settlement amount* for *capacity market participant* 'k' participating with an *hourly demand response resource* at *delivery point* 'm' in *settlement hour* 'h' ("$CATAP^{m}_{k,h}$") shall be determined for each applicable *settlement hour* within the activation window as follows:

$$CATAP^{m}_{k,h} = HDRTAPR \text{ X } HDRDC^{m}_{k,h}$$

4.7J.5.2 in regards to *emergency operating state* activation, the *capacity auction emergency operating state* activation payment *settlement amount* for *capacity market participant* 'k' participating with an *hourly demand response resource* at *delivery point* 'm' in *settlement hour* 'h' ("$CAEOP^{m}_{k,h}$") shall be determined for each applicable *settlement hour* within the activation window as follows:

$$CAEOP^{m}_{k,h} = Max(0, HDRBP^{m}_{k,h} - Max(0,HOEP_{h})) \text{ X } HDRDC^{m}_{k,h}$$

4.7J.5.3 If measurement data for any *metering interval* within a *settlement hour* was not submitted to the *IESO* in accordance with the applicable *market manual,* the *capacity market participant* shall not be eligible to receive a *capacity auction* test activation payment *settlement amount* or a *capacity auction emergency operating state* activation payment *settlement amount* for such *settlement hour*.

Capacity Obligation Availability Charges True-Up Payment

4.7J.6 The *capacity obligation* availability charge true-up *settlement amount* for *capacity market participant* 'k' at *delivery point* 'm' in the relevant *obligation period* ("$CAACT^{m}_{k}$") shall be calculated and disbursed to such *capacity market participant* for each *obligation period* in which (i) the *capacity market participant* was subject to an availability charge pursuant to section 4.7J.2.1 or 4.7J.2.1A; and

(ii) the *capacity market participant offered* an amount of capacity in excess of the *capacity obligation* of its *capacity auction resource* for at least one *settlement hour* within the *availability window* of the applicable *obligation period*. The *capacity auction* availability charge true-up *settlement amount* shall be calculated as follows*:*

$$CAACT^{m}_{k} = (\text{Min}((-1) \times \sum^{TM}((\sum^{D} CAAC^{m}_{k}) + \text{UCAP Adjustment} \times CAAP^{m}_{k} + CAIPA^{m}_{k}), \sum^{H} \text{Max}(0,(RAC_{k} - CCO_{k,h}) \times CACP_{h} \times CNPF_{tm}))$$

Where:

(a) $CAAC^{m}_{k}$ is the *capacity obligation* availability charge *settlement amount* for *capacity market participant* 'k' at *delivery point* 'm' for the relevant *trading day,* as calculated as the sum of the *capacity obligation* availability charge *settlement amount* of each *settlement hour* within the relevant *availability window* determined pursuant to section 4.7J.2.1;

(b) 'UCAP Adjustment' is a de-rate (in %) based on the *hourly demand response* resource's delivered performance during a *capacity auction capacity test* performed during the relevant *obligation period*, as determined in accordance with the applicable *market manual*;

(c) $CAAP^{m}_{k}$ is the *capacity obligation* availability payment *settlement amount* for *capacity market participant* 'k' at *delivery point* 'm' for the relevant *energy market billing period*, as calculated pursuant to section 4.7J.1;

(d) $CAIPA^{m}_{k}$ is the *capacity obligation* in-period *cleared UCAP* adjustment charge *settlement amount* for *capacity market participant* 'k' at *delivery point* 'm' for the relevant *energy market billing period*, as calculated pursuant to section 4.7J.2.9*;*

(e) 'D' is the set of all *trading days* within the relevant *energy market billing period*;

(f) 'tm' is the *energy market billing period* associated with *settlement hour* 'h' within the relevant *obligation period;*

(g) 'TM' is the set of all *energy market billing periods* within the relevant *obligation period;* and

(h) 'H' is the set of all *settlement hours* 'h' within the *availability window* of the relevant *obligation period.*

Capacity Obligation Capacity Auction Charges True-up Payment

4.7J.7 The *capacity obligation* charge true-up *settlement amount* for *capacity market participant* 'k' at *delivery point* 'm' in the relevant *obligation period* ("$CACT^{m}_{k}$") shall be calculated and disbursed to such *capacity market participant* for each *obligation period* in which the *capacity market participant* has a *capacity obligation*. The *capacity obligation* charge true-up *settlement amount* shall be calculated as follows*:*

$$CACT^{m}_{k} = -1 \times Min\ (0, (\sum_{H} TD_{C,k,h}{}^{m} + \sum_{H} TD_{P,k,h}{}^{m}))$$

Where:

(a) $TD_{C,k,h}{}^{m}$ is the total dollar value of all *settlement amounts* 'C' for *capacity market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' in the relevant *obligation period*, where:

a. 'C' is the set of the *settlement amounts* applied in accordance with MR Ch. 9 ss. 4.7J.2.1, 4.7J.2.1A, 4.7J.2.3, 4.7J.2.4, 4.7J.2.7, 4.7J.2.8, and 4.7J.2.9.

(b) $TD_{P\ k,h}{}^{m}$ is the total dollar value of all *settlement amounts* 'P' for *capacity market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' in the relevant *obligation period*, where:

a. 'P' is the set of the *settlement amounts* applied in accordance with MR Ch. 9 ss. 4.7J.1 and 4.7J.6

(c) 'H' is the set of all *settlement hours* 'h' within the *availability window* of the relevant *obligation period*.

Capacity Auction Uplift

4.7J.8 The *capacity auction* uplift *settlement amount* for *market participant* 'k' at *delivery point* 'm' in the *energy market billing period* ("CAU^{m}_{k}") will be calculated and collected from or disbursed to *market participants* for load facilities, as defined in Ontario Regulation 429/04, for each *energy market billing period*. The *capacity auction* uplift *settlement amount* shall be determined in accordance with sections 4.7J.8.1 and 4.7J.8.2. In calculating the *capacity auction* uplift *settlement amount* in this section 4.7J.8, the following subscripts and superscripts shall have the following meanings unless otherwise specified:

(a) 'H' is the set of all *settlement hours* 'h' in the relevant *energy market billing period;*

(b) 'M' is the set of all *delivery points* 'm' of *market participant* 'k';

(c) 'Class B Load' as defined in the applicable *market manual*;

(d) '$EGEI_k$' as defined in the applicable *market manual.*

4.7J.8.1 for *market participants* that are classified as a 'Class A Market Participants' in respect of the relevant load facility, as defined in *Ontario Regulation 429/04*, in accordance with *applicable law,* the *capacity auction* uplift *settlement amount* for such load facility shall be calculated as follows:

$$CAU^{m}_{k} = \Sigma_{H,M} (TD_{C,k,h}{}^{m} * PDF_{k})$$

Where:

(a) '$TD_{C,k,h}{}^{m}$' is total dollar value of all *settlement amounts* 'C' for *capacity market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' in the relevant *energy market billing period*, where:

(i) 'C' is the set of the *settlement amounts* applied in accordance with MR Ch. 9 ss. 4.7J.1, 4.7J.2, 4.7J.3, 4.7J.5, 4.7J.6, and 4.7J.7.

(b) 'PDF_k' is the Peak Demand Factor for 'Class A Market Participant' or Distributor 'k' for the relevant *energy market billing period*, as determined in accordance with *applicable law,* where if the 'Class A Market Participant' or Distributor 'k' ceases to be a 'Class A Market Participant' in respect of the relevant load facility during the relevant *energy market billing period,* the PDF_k shall be pro-rated accordingly.

4.7J.8.2 for *market participants* that are classified as 'Class B Market Participants' in respect of the relevant load facility, as defined in *Ontario Regulation 429/04*, in accordance with *applicable law,* the *capacity auction* uplift *settlement amount* for such load facility shall be calculated in accordance with the following:

(a) for Fort Frances Power Corporation Distribution Inc.:

$$CAU^{m}_{k} = (\Sigma_{H,M}\, TD_{C,k,h}{}^{m} - TD_{C1350,k,h}{}^{m}) \times MAX((\Sigma_{H}{}^{M,T}\, AQEW_{k,h}{}^{m,t} + EGEI_{k} - EEQ),0) / \text{Class B Load}$$

Where:

(i) '$TD_{C,k,h}{}^{m}$' is total dollar value of all *settlement amounts* 'C' for *capacity market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' in the relevant *energy market billing period*, where 'C' is the set of the *settlement amounts* applied in accordance with MR Ch. 9 ss. 4.7J.1, 4.7J.2, 4.7J.3, 4.7J.5, 4.7J.6, and 4.7J.7.

(ii) '$TD_{C1350,k,h}{}^{m}$' is total dollar value of *settlement amounts* applied pursuant to section 4.7J.8.1 for *capacity market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' in the relevant *energy market billing period;*

(iii) 'EEQ' as defined in the applicable *market manual;*

(b) *market participants* that are classified as 'Class B Market Participants' in respect of the relevant load facility in accordance with *applicable law*:

$$CAU^{m}_{k} = (\Sigma_{H,M}\, TD_{C,k,h}{}^{m} - TD_{C1350,k,h}{}^{m}) \times MAX((\Sigma_{H}{}^{M,T}\, AQEW_{k,h}{}^{m,t} + EGEI_{k} - GA_AQEW_{g,k,h,M}{}^{m,t} - PGS_{h,M}),0) / \text{Class B Load}$$

Where:

(i) '$TD_{C,k,h}{}^{m}$' is total dollar value of all *settlement amounts* 'C' for *capacity market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' in the relevant *energy market billing period*, where 'C' is the set of the *settlement amounts* applied in accordance with MR Ch. 9 ss. 4.7J.1, 4.7J.2, 4.7J.3, 4.7J.5, 4.7J.6, and 4.7J.7.

(ii) '$TD_{C1350,k,h}^{m}$' is total dollar value of *settlement amounts* applied pursuant to section 4.7J.8.1 for *capacity market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' in the relevant *energy market billing period;*

(iii) '$GA_AQEW_{g,k,h,M}^{m,t}$' as defined in the applicable *market manual*.

(iv) '$PGS_{h,M}$' as defined in the applicable *market manual*.

4.8 Additional Non-Hourly Settlement Amounts

4.8.1 The *IESO* shall, at the end of each *energy market billing period,* recover from *market participants,* on a pro-rata basis across all allocated quantities of *energy* withdrawn at all *RWMs* and *intertie metering points* during all *metering intervals* and *settlement hours* within that *energy market billing period,* the following amounts:

4.8.1.1 any compensation paid in that *energy market billing period* by the *IESO* pursuant to section 5.3.4 of Chapter 4;

4.8.1.2 any compensation paid in that *energy market billing period* by the *IESO* pursuant to section 5.3.4 of Chapter 5;

4.8.1.3 any out-of-pocket expenses paid in that *energy market billing period* by the *IESO* pursuant to section 6.7.4 of Chapter 5;

4.8.1.4 any compensation paid in that *energy market billing period* by the *IESO* pursuant to section 8.4A.9 of Chapter 7;

4.8.1.5 any costs incurred in that *energy market billing period* by the *IESO* to acquire *emergency energy* pursuant to section 2.3.3A of Chapter 5;

4.8.1.6 any reimbursement paid in that *energy market billing period* by the *IESO* pursuant to section 2.1A.14;

4.8.1.7 [Intentionally left blank – section deleted]

4.8.1.8 [Intentionally left blank – section deleted]

4.8.1.9 any compensation paid in that *energy market billing period* by the *IESO* pursuant to section 4.7B.3;

4.8.1.10 any compensation paid in that *energy market billing period* by the *IESO* pursuant to section 4.7C;

4.8.1.11 any compensation paid in that *energy market billing period* by the *IESO* pursuant to section 8.2.6 of Chapter 5;

4.8.1.12 any compensation paid in that *energy market billing period* by the *IESO* under section 4.7D;

4.8.1.13 any compensation paid in that *energy market billing period* by the *IESO* under section 4.7E; and

4.8.1.14 [Intentionally left blank – section deleted]

4.8.1.15 [Intentionally left blank – section deleted]

4.8.1.16 any compensation paid in that *energy market billing period* by the *IESO* under section 4.7G.

4.8.2 The *IESO* shall, at the end of each *energy market billing period*, distribute to *market participants*, on a pro-rata basis across all allocated quantities of *energy* withdrawn at all *RWMs* and *intertie metering points* during all *metering intervals* and *settlement hours* within that *energy market billing period*, the following amounts:

4.8.2.1 any compensation received by the *IESO* for the provision of *emergency energy* pursuant to section 4.4A.1 of Chapter 5;

4.8.2.2 any compensation received by the *IESO* as a result of a local market power investigation as set out in sections 1.7.1 and 1.7.2 of Appendix 7.6;

4.8.2.3 [Intentionally left blank – section deleted]

4.8.2.4 [Intentionally left blank – section deleted]

4.8.2.5 any payments recovered by the *IESO* in accordance with sections 3.5.1A and 3.5.6E;

4.8.2.6 any adjustments made by the *IESO* in accordance with section 3.5.6;

4.8.2.7 [Intentionally left blank – section deleted]

4.8.2.8 any proceeds from the day-ahead import failure charge that are not distributed as a component of *hourly uplift* under section 3.9.4;

4.8.2.9 any proceeds from the real-time import failure charge or the real- time export failure charge that in accordance with section 3.9.5 are not distributed as a component of *hourly uplift*;

4.8.2.10 any proceeds from the recovery of congestion management *settlement* credits or other *settlement amounts* in accordance with section 6.6.10A.2 of Chapter 3, excluding any payments recovered under section 4.18.1.6 of Chapter 8;

4.8.2.11 any recovery of day-ahead *intertie offer* guarantee payments pursuant to section 3.3A.13 of Chapter 7;

4.8.2.12 [Intentionally left blank – section deleted]

4.8.2.13 any recovery of payments made by the *IESO* under section 3.5.9;

4.8.2.14 any proceeds from the day-ahead *generator* withdrawal charge under section 3.8F;

4.8.2.15 any recovery of payments made by the *IESO* under section 3.5.10;

4.8.2.16 any recovery of payments made by the *IESO* under sections 4.7B.4A, 4.7D.7 or 4.7D.8;

4.8.2.17 any recovery of payments made by the *IESO* under section 3.5.7A; and

4.8.2.18 any recovery of payments made by the *IESO* under section 3.5.11.

4.8.3 The *IESO* shall, at the end of each *energy market billing period,* recover from *market participants,* in the manner specified in the applicable *market manual,* the following amounts:

4.8.3.1 [Intentionally left blank – section deleted];

4.8.3.2 [Intentionally left blank – section deleted];

4.8.3.3 any compensation for *capacity market participants* paid in that *energy market billing* period by the *IESO* pursuant to section 4.7J.

4.8.3.4 any funds borrowed by the *IESO* and any associated interest costs incurred by the *IESO* in the preceeding *energy market billing period* pursuant to section 6.16.6.2.

4.8.4 The *IESO* shall distribute to *market participants*, in the manner specified in the applicable *market manual*, the following amounts:

4.8.4.1 [Intentionally left blank – section deleted];

4.8.4.2 [Intentionally left blank – section deleted];

4.8.4.3 any adjustments to *capacity market participant* payments pursuant to section 4.7J.

5. Market Power Mitigation

5.1 Settlement of Market Power Mitigation Rebate

5.1.1 Any payment received by the *IESO* pursuant to the terms of any agreement:

5.1.1.1 to which the *IESO* is required by its *licence* to be a party;

5.1.1.2 which incorporates the terms of a directive issued by the *Minister* to the *Ontario Energy Board* pursuant to subsection 28(1) of the *Ontario Energy Board Act, 1998*; and

5.1.1.3 which provides for the payment to the *IESO* of a rebate of certain *settlement amounts*,

shall be distributed in accordance with the *IESO licence*, as amended from time to time.

5.1.2 [Intentionally left blank]

5.1.3 [Intentionally left blank]

5.1.4 [Intentionally left blank]

5.1.5 [Intentionally left blank]

5.1.6 [Intentionally left blank]

6. Settlement Statements

6.1 Communication of Settlement Information

6.1.1 All communications between *market participants* and the *IESO* relating to the *settlement* process shall be effected using the *electronic information system* and

other such means of communication as may be specified in applicable *market manuals*.

6.1.2 If there is a failure of a communication system and it is not possible to communicate in accordance with the *electronic information system* or where applicable, the means of communication specified in the applicable *market manuals*, then the *IESO* or the *market participant*, as the case may be, shall communicate information relating to the *settlement process* by facsimile or other alternative means specified by the *IESO*.

6.2 Settlement Schedule and Payments Calendar

6.2.1 By November 1 of each year, the *IESO* shall *publish* the *IESO Settlement Schedule & Payments Calendar* or *SSPC* for the following calendar year showing the dates referred to in sections 6.3.2 to 6.3.23 as fixed dates within such calendar year.

6.2.2 If the *IESO* becomes aware of any change required to the *SSPC*, the *IESO* shall *publish* an updated *SSPC* to reflect the necessary changes. The *IESO* shall use reasonable efforts to provide *market participant*s with at least two weeks' notice of any changes to the *SSPC*.

6.2.3 The *SSPC* is *published* by the *IESO* for *market participant* ease of reference and the applicable dates that are binding on the *IESO* and *market participant*s are the dates determined in accordance with sections 6.3.1 to 6.3.23. Notwithstanding anything to the contrary, any reference in these *market rules* to the *SSPC* shall be deemed to be references to the dates specified in accordance with sections 6.3.1 to 6.3.23.

6.3 Settlement Cycles

6.3.1 Subject to section 6.3.24 to 6.3.33, section 6.3.2 to 6.3.23 set out the applicable dates for the *settlement process* and issuance of *settlement statements* and *invoices*.

TR auctions

6.3.2 The *preliminary settlement statement* for each *trading day* for all rounds of any *TR auction* that is concluded on such *trading day* shall be issued two *business days* after the *trading day*.

6.3.3 After the *preliminary settlement statement* referred to in section 6.3.2 is issued, each *market participant* shall have two *business days* in which to notify the *IESO*

of errors or omissions in the *preliminary settlement statement* in accordance with section 6.8.

6.3.4 The *final settlement statement* for each *trading day* for all rounds of any *TR auction* that is concluded on such *trading day* shall be issued six *business days* after the *trading day*.

6.3.5 After the *final settlement statement* referred to in section 6.3.4 is issued, each *market participant* shall have two *business days* in which to notify the *IESO* of errors or omissions in the *final settlement statement* in accordance with section 6.8.

6.3.6 Where an adjustment is required pursuant to sections 6.8.9.2(b), 6.8.9.2(c), 6.9.1.2(b), 6.9.1.2(c), or 6.10.4.1(a) or as otherwise required, *recalculated settlement statements* for each *trading day* for all rounds of any *TR auction* that is concluded on such *trading day* shall be issued at the following times:

a. the first *recalculated settlement statement* shall, where applicable, be issued on the last *business day* of the month immediately following the month of the *trading day* to which the *recalculated settlement statement* relates;

b. the *final recalculated settlement statement* shall be issued on the last *business day* of the month that is 22 months after the month of the *trading day* to which the *final recalculated settlement* relates. For greater certainty, the *IESO* shall always issue the *final recalculated settlement*; and

c. notwithstanding the foregoing, and at the *IESO*'s sole discretion, the *IESO* may issue, either in lieu of or in addition to the *recalculated settlement statement* referred to in section 6.3.6(a)-(b), an ad hoc *recalculated settlement statement* at any time up to and including the scheduled date to issue the *final recalculated settlement* for the relevant *trading day*. An ad hoc *recalculated settlement statement* may relate to any *trading day* in the preceding 23-month period.

6.3.7 After a *recalculated settlement statement* referred to in section 6.3.6 is issued, each *market participant* shall have two *business days* in which to notify the *IESO* of errors or omissions in the *recalculated settlement statement* in accordance with section 6.8.

6.3.8 The *IESO* shall issue one invoice to each *market participant*, covering all *trading days* within a *billing period*, on the same business day it issues the *final settlement statement* for the last *trading day* of that *billing period*.

6.3.9 The *market participant payment date* for all rounds of any *TR auction* that is concluded during such *billing period* shall be the second *business day* following the issuance of the *invoice*.

6.3.10 Each *market participant* shall initiate the *electronic funds transfer* process in accordance with the provisions of section 6.14 so as to ensure that the *market participant*'s payments in respect of all rounds of any *TR auction* that is concluded in each *billing period* reach the *IESO settlement clearing account* no later than the *close of banking business* (of the bank at which the *IESO settlement clearing account* is held) on the *market participant payment date*.

6.3.11 The *IESO payment date* for all rounds of any *TR auction* that is concluded during such *billing period* shall be the second *business day* after the corresponding *market participant payment date*.

6.3.12 The *IESO* shall initiate the *electronic funds transfer* process in accordance with the provisions of section 6.14 so as to ensure that the sums owing to each *market participant* in respect of all rounds of any *TR auction* that is concluded in each *billing period* reach each *market participant*'s *settlement account* no later than the *close of banking business* (of the bank at which the *market participant*'s *settlement account* is held) on the *IESO payment date*.

Real-Time Markets

6.3.13 The *preliminary settlement statement* for each *trading day* in the *real-time markets* and in the *TR market*, other than in respect of the element referred to in section 6.3.2, shall be issued ten *business days* after the *trading day*.

6.3.14 After the *preliminary settlement statement* referred to in section 6.3.13 is issued, each *market participant* shall have six *business day*s to notify the *IESO* of errors or omissions in the *preliminary settlement statement* in accordance with section 6.8.

6.3.15 The *final settlement statement* for each *trading day* in the *real-time market*s and in the *TR market*, other than in respect of the element referred to in section 6.3.2, shall be issued ten *business days* after the issuance of the *preliminary settlement statement* for that *trading day*.

6.3.16 After the *final settlement statement* referred to in section 6.3.15 is issued, each *market participant* shall have six *business day*s in which to notify the *IESO* of errors or omissions in the *final settlement statement* in accordance with section 6.8.

6.3.17 Where an adjustment is required pursuant to sections 6.8.9.2(b), 6.8.9.2(c), 6.9.1.2(b), 6.9.1.2(c), or 6.10.4.1(a), or as otherwise required, *recalculated settlement statements* for each *trading day* in the *real-time markets* and in the *TR market*, other than in respect of the element referred to in section 6.3.2, shall be issued at the following times:

a. the first *recalculated settlement statement* shall, where applicable, be issued on the same date as the *invoice* for the month that is one month after the month which contains the *trading day* to which the *recalculated settlement statement* relates. For greater certainty, the first *recalculated settlement statement* is issued on the same date for all the *trading day*s of a given month;

b. the second *recalculated settlement statement* shall, where applicable, be issued on the same date as the *invoice* for the month that is two months after the month which contains the *trading day* to which the *recalculated settlement statement* relates. For greater certainty, the second *recalculated settlement statement* is issued on the same date for all the *trading day*s of a given month;

c. the third *recalculated settlement statement* shall, where applicable, be issued on the same date as the *invoice* for the month that is five months after the month which contains the *trading day* to which the *recalculated settlement statement* relates. For greater certainty, the third *recalculated settlement statement* is issued on the same date for all the *trading day*s of a given month;

d. the fourth *recalculated settlement statement* shall, where applicable, be issued on the same date as the *invoice* for the month that is eight months after the month which contains the *trading day* to which the *recalculated settlement statement* relates. For greater certainty, the fourth *recalculated settlement statement* is issued on the same date for all the *trading day*s of a given month;

e. the fifth *recalculated settlement statement* shall, where applicable, be issued on the same date as the *invoice* for the month that is eleven months after the month which contains the *trading day* to which the *recalculated settlement statement* relates. For greater certainty, the fifth *recalculated settlement statement* is issued on the same date for all the *trading day*s of a given month;

f. the sixth *recalculated settlement statement* shall, where applicable, be issued on the same date as the *invoice* for the month that is seventeen months after the month which contains the trading day to which the *recalculated settlement statement* relates. For greater certainty, the sixth *recalculated settlement statement* is issued on the same date for all the *trading day*s of a given month;

g. the *final recalculated settlement statement* shall be issued on the same date as the *invoice* for the month that is 23 months after the month which contains the

trading day to which the *recalculated settlement statement* relates. For greater certainty, the *IESO* shall always issue the *final recalculated settlement statement* and the *final recalculated settlement statement* is issued on the same date for all the *trading day*s of a given month; and

h. notwithstanding the foregoing, and at the *IESO*'s sole discretion, the *IESO* may issue, either in lieu of or in addition to the *recalculated settlements statements* referred to in section 6.3.17(a)-(g), an ad hoc *recalculated settlement statement* at any time up to and including the scheduled date to issue the *final recalculated settlement statement* for the relevant *trading day*. An ad hoc *recalculated settlement statement* may relate to any *trading day* that was first invoiced in the preceding 23-month period.

6.3.18 After a *recalculated settlement statement* referred to in section 6.3.17 is issued, other than in respect of a *final recalculated settlement statement*, each *market participant* shall have six *business day*s in which to notify the *IESO* of errors or omissions in the *recalculated settlement statement* in accordance with section 6.8.

6.3.19 The *IESO* shall issue one *invoice* to each *market participant*, covering all *trading day*s within a *billing period*, and such other information specified in accordance with section 6.12.1, on the same day it issues the *preliminary settlement statement* for the last *trading day* of that *billing period*.

6.3.20 The *market participant payment date* for each *real-time market billing period* and for each *TR market billing period* shall be the second *business day* following the issuance of the *invoice*.

6.3.21 Each *market participant* shall initiate the *electronic funds transfer* process in accordance with the provisions of section 6.14 so as to ensure that the *market participant*'s payments for each *real-time market billing period* and for each *TR market billing period* reach the *IESO settlement clearing account* no later than the *close of banking business* (of the bank at which the *IESO settlement clearing account* is held) on the *market participant payment date*.

6.3.22 The *IESO payment date* for each *real-time market billing period* and for each *TR market billing period* shall be the second *business day* after the *market participant payment date*.

6.3.23 The *IESO* shall initiate the *electronic funds transfer* process in accordance with the provisions of section 6.14 so as to ensure that the sums owing to each *market participant*, *forecasting entity*, and to each *transmitter* for each *real-time market billing period* and for each *TR market billing period* reach the *market participant*'s *settlement account* or the *transmitter*'s *transmission services settlement account*, as the case may be, no later than the *close of banking business*

(of the bank at which the *market participant*'s *settlement account* or the *transmitter*'s *transmission services settlement account* is held) on the *IESO payment date*.

Delays

6.3.24 The *IESO* may delay the issuance of *settlement statement*s for a *trading day* to a date later than that provided for in sections 6.3.2, 6.3.4, 6.3.6, 6.3.13, 6.3.15, and 6.3.17, as the case may be, where, in the *IESO*'s opinion significant inaccuracies exist in the *settlement statements* such as to justify such delay.

6.3.25 Where the *IESO* delays the issuance of one or more *settlement statement*s for a *trading day* pursuant to section 6.3.24:

6.3.25.1 the issuance of *settlement statement*s for any immediately succeeding *trading day*s that would otherwise be required pursuant to sections 6.3.2, 6.3.4, 6.3.6, 6.3.13, 6.3.15, and 6.3.17, as the case may be, to be issued prior to the date referred to in section 6.3.26.1 shall be delayed to that date or to such later date(s) as may be determined and published by the *IESO*; and

6.3.25.2 the date by which *market participant*s must notify the *IESO* of errors or omissions in any delayed *settlement statement*s for each of the *trading day*s referred to in section 6.3.25.1 shall be delayed by the same number of days which the *settlement statement* to which the date relates is delayed.

6.3.26 Where the *IESO* delays the issuance of a *settlement statement* for a *trading day* pursuant to section 6.3.24, the *IESO* shall publish notice of such delay, which notice shall indicate:

6.3.26.1 the date on which such *settlement statement* shall be issued in lieu of the date referred to in sections 6.3.2, 6.3.4, 6.3.6, 6.3.13, 6.3.15, and 6.3.17, as the case may be;

6.3.26.2 the date by which *market participants* must notify the *IESO* of errors or omissions in such *settlement statement*s, determined in accordance with section 6.3.25.2; and

6.3.26.3 whether the *IESO* intends to invoke the estimated *invoice* procedure referred to in section 6.3.27.

6.3.27 Where the *IESO* determines that it will be unable to issue *invoice*s calculated in accordance with section 6.12.1 in respect of a given *energy market billing period*

on or within one *business day* of the applicable date determined in accordance with section 6.3.8 or 6.3.19, the *IESO* shall, within two *business days* of the applicable date, issue to each *market participant* an estimated *invoice* for such *energy market billing period* in a net amount determined in accordance with section 6.3.29.

6.3.28 Where the *IESO* intends to invoke the estimated *invoice* procedure referred to in section 6.3.27 or to delay the issuance of *invoice*s pursuant to section 6.3.33, the *IESO* shall *publish* a notice indicating whether the *IESO* intends, in accordance with section 6.3.31, to delay each of the *market participant payment date* and the *IESO payment date* associated with such *invoice*s or estimated *invoice*s.

6.3.29 The amount of an estimated *invoice* issued to a *market participant* pursuant to section 6.3.27 shall, subject to section 6.3.30, be equal to the aggregate of:

6.3.29.1 the net total amount for that *market participan*t for all *trading day*s that occurred during the *energy market billing period* prior to the date on which the issuance of *preliminary settlement statements* commenced to be delayed pursuant to section 6.3.24 or 6.3.25.1, as the case may be;

6.3.29.2 for each *trading day* in the *energy market billing period* that occurred subsequent to the date referred to in section 6.3.29.1, the net total amount for that *market participant* as set forth in the *final settlement statement*s issued to that *market participant* in the preceding *energy market billing period*, commencing with the *final settlement statement* issued for the last *trading day* of such preceding *energy market billing period* and using a number of *final settlement statement*s equal to the number of *trading day*s in the current *energy market billing period* occurring subsequent to the date referred to in section 6.3.29.1; and

6.3.29.3 for greater certainty, any net total amount for that *market participant* reflected on a *recalculated settlement statement* which would have otherwise been included on the *invoice* for the relevant *energy market billing period* shall not be reflected on the estimated *invoice*.

6.3.30 Where the data required to determine the amount of an estimated *invoice* in accordance with section 6.3.29 is not readily available at the relevant time, the *IESO* shall issue to each applicable *market participant* an estimated *invoice* in an amount equal to:

6.3.30.1 the net amount of the *invoice* issued to the *market participant* for the preceding *energy market billing period* minus any amounts on such *invoice* included on a *recalculated settlement statement*; or

6.3.30.2 zero, if no *invoice* was issued to the *market participant* for the preceding *energy market billing period*.

6.3.31 Where the *IESO* issues estimated *invoice*s pursuant to section 6.3.28 or delays the issuance of *invoice*s pursuant to section 6.3.33 in respect of a given *energy market billing period*, the *IESO* may, where the delay resulting in the need to issue an estimated *invoice* or to delay the issuance of the *invoice*s has or is likely to have an adverse effect on the operation of the *IESO settlement clearing account*, delay each of the *market participant payment date* and the *IESO payment date* associated with such estimated *invoice* or delayed *invoice* by one *business day* relative to the periods referred to in sections 6.3.9 or 6.3.15, or sections 6.3.11 or 6.3.17, respectively.

6.3.32 Where the *IESO* issues to a *market participant* an estimated *invoice* in respect of a given *energy market billing period* pursuant to section 6.3.27, the *IESO* shall adjust the *invoice* issued to the *market participant* for the next *energy market billing period* to reflect any net difference between the amount of the estimated *invoice* and the amount that would have been set forth on the *market participant*'s *invoice* had the *invoice* been calculated in accordance with section 6.12.1 rather than estimated in accordance with section 6.3.27, including adding any net amounts reflected on any *recalculated settlement statement*s for the same *energy market billing period*.

6.3.33 Where the *IESO* determines that:

6.3.33.1 it will be unable to issue *invoice*s calculated in accordance with section 6.12.1 in respect of a given *energy market billing period* on the applicable date specified in the accordance with sections 6.3.8 or 6.3.19 by reason of the delay in issuance of *settlement statement*s referred to in section 6.3.24 or 6.3.25.1, or for any other reason; and

6.3.33.2 it is able to issue such *invoice*s within one *business day* of the applicable date specified in accordance with sections 6.3.8 or 6.3.19 such that the estimated *invoice* procedure referred to in sections 6.3.27 to 6.3.32 does not apply,

the *IESO* may delay the issuance of such *invoice*s for such *energy market billing period* for a period of up to one *business day* relative to the applicable date specified in accordance with sections 6.3.8 or 6.3.19, as the case may be.

6.4 Settlement Statement Process

6.4.1 The *IESO* shall issue *settlement statement*s to each *market participant* to cover each trading day in accordance with section 6.5, section 6.6 and section 6.7, and

shall provide the *settlement* data included in such *settlement statements* into the *settlement process*.

6.4.2 For each *settlement statement*, the *IESO* shall calculate a net *settlement amount* for each *market participant* for the *trading day*. The net *settlement amount* shall be comprised of:

6.4.2.1 the aggregate of the trading amounts from each transaction in each *settlement hour* in the *trading day*; and

6.4.2.2 the aggregate of the amounts for the purchase or sale of *TR*s in all rounds of any *TR auction* that is concluded on the *trading day*,

adjusted to reflect any fees payable by the *market participant* and any other adjustment amounts payable or receivable pursuant to these *market rules.*

6.4.3 The net *settlement amount* referred to in section 6.4.2 shall be a positive or negative dollar amount for each *market participant* and:

6.4.3.1 where the net *settlement amount* for a *market participant* is negative, the absolute value of the *settlement amount* shall be an amount payable by the *market participant* to the *IESO*; or

6.4.3.2 where the net *settlement amount* for a *market participant* is positive, the *settlement amount* shall be an amount receivable by the *market participant* from the *IESO*.

6.4.4 *Settlement statements* shall be considered issued to *market participant*s when issued in accordance with the applicable *market manuals.*

6.4.5 It is the responsibility of each *market participant* to notify the *IESO* if it fails to receive a *preliminary settlement statement*, *final settlement statement*, or *final recalculated settlement statement* on the date specified for issuance of such *settlement statement* in accordance with sections 6.3.2 to 6.3.23 or, where applicable, on any of the dates referred to in section 6.3.25.1 and 6.3.26. Each *market participant* shall be deemed to have received such *settlement statements* on the relevant date specified in accordance with sections 6.3.2 to 6.3.23 or, where applicable, on any of the dates referred to in sections 6.3.25.1 and 6.3.26, unless it notifies the *IESO* to the contrary within two *business days* of date specified for issuance of such *settlement statement* in accordance with sections 6.3.2 to 6.3.23.

6.4.6 In the event that a *market participant* notifies the *IESO* that it has failed to receive a *settlement statement* on the date specified for that *settlement statement* in

accordance with sections 6.3.2 to 6.3.23 or, where applicable, on any of the dates referred to in sections 6.3.25.1 and 6.3.26, the *IESO* shall re-send such *settlement statement*, in which case the *settlement statement* shall be considered to have been received on the date the re-sent *settlement statement* is sent to the *market participant*.

6.5 Preliminary Settlement Statement Coverage

6.5.1 The *IESO* shall issue to each *market participant* separate *preliminary settlement statements* to cover:

6.5.1.1 transactions in all rounds of any *TR auction* that is concluded on a given *trading day*; and

6.5.1.2 transactions in the *real-time markets* and in the *TR market*, other than in respect of the element referred to in section 6.5.1.1,

6.5.1.3 any adjustments which may be required pursuant to the *market rules*, including section 6.8, section 6.9, matters identified in section 6.8.12.4, and the processes outlined in section 10.4 of Chapter 6 and section 6C of Chapter 10,

6.5.1.4 in accordance with the timelines set forth in sections 6.3.2, 6.3.13, 6.3.24 and 6.3.25.1, as may be applicable.

6.5.2 *Preliminary settlement statements* related to each *market participant* for all rounds of any *TR auction* that is concluded on a given *trading day* shall include, in electronic format, for each *settlement hour* of the relevant *trading day* or for each such *TR auction*, as the case may be, referenced by applicable *charge type*:

6.5.2.1 the *hourly Ontario energy price* in that *settlement hour*;

6.5.2.2 the payment for the *settlement hour*, either from the *market participant* to the *IESO*, or from the *IESO* to the *market participant*;

6.5.2.3 all fees, charges, credits and payments applicable to the *market participant* in respect of the purchase or sale of a *TR* in all rounds of such *TR auction*; and

6.5.2.4 for each type of charge listed, the total *trading day's* charges and a *billing period*-to-date total.

6.5.3 *Preliminary settlement statements* related to each *market participant* for the *real-time markets* and for the *TR market,* other than in respect of the element referred

to in section 6.5.2, shall include the *settlement amounts,* prices and quantities described in section 6.5.4, presented as follows:

6.5.3.1 for each hourly *settlement amount* referred to in section 3, by *metering interval* or *settlement hour*, as the case may be, depending upon the manner of calculation of the *settlement amount* as described in section 3;

6.5.3.2 for each non-hourly *settlement amount* referred to in section 4 or 5 that is required to be calculated over or in respect of a given *billing period*, by *billing period*, provided that such non-hourly *settlement amount*s shall be included only in the *preliminary settlement statement* issued in respect of the last *trading day* of a *billing period*; and

6.5.3.3 for each non-hourly *settlement amount*, other than those referred to in section 6.5.3.2, by *metering interval*, *settlement hour*, or *trading day*, as the case may be, depending upon the time period over or with respect to which the relevant *settlement amount* is required to be calculated pursuant to section 4, or 5.

6.5.4 The *preliminary settlement statement*s referred to in section 6.5.3 shall be in electronic format and shall set forth, for the *market participant* to whom the *preliminary settlement statement* is issued and referenced by applicable charge type:

6.5.4.1 the *energy* injected or withdrawn by each of that *market participant*'s *registered facilities* as determined in each of the *market schedule* and the *real-time schedule*.

6.5.4.2 the allocated quantities of *energy* withdrawn or injected by each of that *market participant*'s *registered facilities*.

6.5.4.3 the aggregate quantity of each class of *operating reserve* provided by each of that *market participant*'s *registered facilities* as determined in each of the *market schedule* and the *real-time schedule*.

6.5.4.4 the aggregate quantities or capacities, as the case may be, of each *contracted ancillary service* scheduled and provided from each of that *market participant*'s *registered facilities*;

6.5.4.5 the *physical bilateral contract quantities* for that *market participant*;

6.5.4.6 the availability payments to be made in each *billing period* under *reliability must-run contracts* to each of that *market participant*'s *reliability must-run resources*;

6.5.4.7 details of performance incentive payments or penalties applicable to the *market participant*;

6.5.4.8 the *energy market price* applying to each of that *market participant*'s *registered facilities*;

6.5.4.9 the applicable 5-minute price for each class of *operating reserve* for each of that *market participant*'s *registered facilities*;

6.5.4.10 detailed calculations of applicable *transmission services charges*, and the *market participant*'s share of these;

6.5.4.11 the total of each type of *contracted ancillary service* charges, and the *market participant*'s share of these;

6.5.4.12 all *real-time market* fees, charges and payments applicable to the *market participant* and the basis for deriving those fees, charges or payments;

6.5.4.13 for each type of charge listed, the total *trading day*'s charges and a *billing period*-to-date total; and

6.5.4.14 all *TR market* fees, charges, credits and payments applicable to the *market participant*.

6.6 Final Settlement Statement Coverage

6.6.1 The *IESO* shall issue to each *market participant* separate *final settlement statements* to cover:

6.6.1.1 transactions in all rounds of any *TR auction* that is concluded on a given *trading day*;

6.6.1.2 transactions in the *real-time markets* and in the *TR market*, other than in respect of the element referred to in section 6.6.1.1; and

6.6.1.3 adjustments required pursuant to the *market rules*, including section 6.8, section 6.9, matters identified in section 6.8.12.4, and the processes outlined in section 10.4 of Chapter 6 and section 6C of Chapter 10,

6.6.1.4 in accordance with the timelines set forth in sections 6.3.4, 6.3.14, 6.3.24, and 6.3.25.1, as may be applicable.

6.6.2 The *final settlement statement* shall be in the same form as the *preliminary settlement statement* and shall include all of the information provided in the

preliminary settlement statement, as amended following the validation procedure set forth in section 6.8 and 6.9, where applicable.

6.6.3 In accordance with the provisions of sections 6.8.9, 6.8.11, 6.9.1.2, 6.9.4, *final settlement statements* shall include any required adjustments as a credit or debit to each affected *market participant* resulting from *settlement* disagreements that have been resolved prior to the issue date of the applicable *final settlement statement*.

6.6.4 Each *market participant* that receives a *final settlement statement* is required to pay any net debit amount shown in the *final settlement statement* on the corresponding *market participant payment date* and shall be entitled to receive any net credit amount shown in the *final settlement statement* on the corresponding *IESO payment date*, whether or not there is any outstanding disagreement regarding the amount of such debit or credit.

6.7 Recalculated Settlement Statement Coverage

6.7.1 The *IESO* shall, when applicable, issue to each *market participant* separate *recalculated settlement statements* to cover adjustments required pursuant to the *market rules*, including section 6.8, section 6.9, matters identified in section 6.8.12.4, and the processes outlined in section 10.4 of Chapter 6 and section 6C of Chapter 10 in respect of:

6.7.1.1 transactions in all rounds of any *TR auction* that is concluded on a given *trading day*; and

6.7.1.2 transactions in the *real-time markets* and in the *TR market*, other than in respect of the element referred to in section 6.7.1.1,

6.7.1.3 accordance with the timelines set forth in sections 6.3.6, 6.3.17, 6.3.24, 6.3.25.1, as may be applicable.

6.7.2 The *recalculated settlement statement* shall be in the same form as the *final settlement statement* and shall include all of the information provided in the most recently issued *settlement statement* for the *trading day* for which the *recalculated settlement statement* relates, as amended following the validation procedure set forth in section 6.8 and 6.9 and the processes outlined in section 10.4 of Chapter 6 and section 6C of Chapter 10, where applicable.

6.7.3 In accordance with the provisions of sections 6.8.9, 6.8.11, 6.9.1.2, 6.9.4, and the processes outlined in section 10.4 of Chapter 6 and section 6C of Chapter 10, where applicable, *recalculated settlement statements* shall include any required adjustments as a credit or debit to each affected *market participant* resulting from

settlement disagreements that have been resolved prior to the issue date of the applicable *recalculated settlement statement*.

6.7.4 Each *market participant* that receives a *recalculated settlement statement* is required to pay any net debit amount shown in the *recalculated settlement statement* on the corresponding *market participant payment date* and shall be entitled to receive any net credit amount shown in the *recalculated settlement statement* on the corresponding *IESO payment date*, whether or not there is any outstanding disagreement regarding the amount of such debit or credit.

6.8 Market Participant Validation of Settlement Statements

6.8.1 Each *market participant* shall review all of its *settlement statements* upon receipt. Subject to the terms of this section 6.8, a *market participant* may register a disagreement with the *IESO* with respect to any *settlement statement* other than a *final recalculated settlement statement* by filing a *notice of disagreement* in accordance with the timelines set forth in sections 6.3.3, 6.3.5, 6.3.7, 6.3.14, 6.3.16, 6.3.18, and 6.3.25.2, as the case may be.

6.8.2 Subject to section 6.8.12, if a *market participant* disagrees with any item or calculation set forth in a *preliminary settlement statement* that it has received, or considers that there is an omission in such *preliminary settlement statement,* it may provide the *IESO* with a *notice of disagreement* in such form as may be established by the *IESO* and in accordance with section 6.8.4.

6.8.3 Subject to section 6.8.12, if a *market participant* disagrees with an item or calculation set forth on a *final settlement statement* or a *recalculated settlement statement*, other than a *final recalculated settlement statement*, that:

a. differs in amount from the same item or calculation set forth on an earlier *settlement statement* corresponding to the same *trading day* and is identified as associated with an adjustment flag;

b. is an item or calculation which is new and not set forth on an earlier *settlement statement* corresponding to the same *trading day* and is identified as associated with an adjustment flag; or

c. the *market participant* considers that there is an omission in such *settlement statement*, including where the *IESO* does not issue a *recalculated settlement statement* because it has determined an adjustment is not necessary and the *market participant* disagrees with such determination, it may provide the *IESO* with a *notice of disagreement* in such form as may be established by the *IESO* and in accordance with section 6.8.4. For greater certainty, a *market participant* shall not provide a *notice of disagreement* to the *IESO* if the item

or calculation on a *final settlement statement* or *recalculated settlement statement* with which the *market participant* disagrees is not captured by sections (a) or (b) above.

6.8.4 *Notices of disagreement* shall relate to only one *settlement statement* and shall include at least the following information:

6.8.4.1 the date of issuance of the *settlement statement* in question;

6.8.4.2 the *dispatch day* in question;

6.8.4.3 the item(s) or omission(s) in question;

6.8.4.4 clearly state, with supporting material, the reasons for the disagreement;

6.8.4.5 where applicable and with supporting material, the proposed adjustment to the data used to calculate any relevant *settlement amount* on the *settlement statement*; and

6.8.4.6 where applicable and with supporting material, the proposed correction to any calculation of the relevant *settlement amount* on the *settlement statement.*

6.8.5 Where a *notice of disagreement* includes a proposed adjustment to:

6.8.5.1 *physical bilateral contract data*; or

6.8.5.2 any data of a comparable nature which may be identified by the *IESO* from time to time,

the *IESO* shall notify any other *market participant* to whom items 6.8.5.1 or 6.8.5.2 relates of such proposed adjustment prior to taking any action under section 6.8.9.

6.8.6 The *notice of disagreement* issued by the *market participant* shall be acknowledged by the *IESO* upon receipt.

6.8.7 The issuance of a *notice of disagreement* shall not remove the obligation of the *market participant* to settle any *invoice* based on the *preliminary settlement statement*, *final settlement statement* or *recalculated settlement statement*.

6.8.8 Subject to section 6.8.12 the *IESO* shall use the information provided in and with a *notice of disagreement*, and any other information available to the *IESO,* to consider the subject-matter of the disagreement and determine the necessary corrections, if any.

6.8.9 Following the determination described in section 6.8.8, the *IESO* shall inform the *market participant* of its determination, provide the *market participant* the opportunity to respond within ten *business days*, and, after considering any such response, take one of the following actions:

6.8.9.1 if the *IESO* concludes that no adjustment or correction is required in the *settlement statement,* it shall take no further action; or

6.8.9.2 if the *IESO* concludes that an adjustment or correction is required, take one of the following actions:

a. if the *notice of disagreement* is with respect to an item or calculation on a *preliminary settlement statement* and the *IESO* concludes an adjustment is required prior to the issuance of the corresponding *final settlement statement*, the *IESO* shall adjust the corresponding *final settlement statement* accordingly;

b. if the *notice of disagreement* is with respect to an item or calculation on a *preliminary settlement statement* and the *IESO* concludes an adjustment is required after the issuance of the corresponding *final settlement statement*, the *IESO* shall make the adjustment in the next scheduled *recalculated settlement statement.* For clarity, where the *notice of disagreement* relates to a *trading date* prior to the *IESO* commencing the issuance of *recalculated settlement statements,* the *IESO* shall make the adjustment on a subsequent *preliminary settlement statement*; or

c. if the *notice of disagreement* is with respect to an item or calculation on a *final settlement statement* or a *recalculated settlement statement*, the *IESO* shall make the adjustment in the next scheduled *recalculated settlement statement*.

6.8.10 If the *IESO* does not make its determination before the date for issuing any subsequent *settlement statements,* as applicable, the *IESO* shall issue such *settlement statements* without taking into account the disagreement.

6.8.11 Any changes required to be made in a *final settlement statement* or *recalculated settlement statement* as a result of the validation process described in this section 6.8 shall, subject to section 6.18.3, be included as:

6.8.11.1 a debit or credit in the *final settlement statement*, or

6.8.11.2 if the *IESO* has already issued the relevant *final settlement statement* prior to the determination of the required change, as an *adjustment period*

allocation to a *recalculated settlement statement,* or a subsequant *preliminary settlement statement* where the *notice of disagreement* relates to a *trading date* prior to the *IESO* commencing the issuance of *recalculated settlement statements,* issued for each affected *market participant*. If, after making all reasonable efforts to do so, the *IESO* cannot recover these amounts from or distribute these amounts to a former *market participant*, such amounts shall then be included as a c*urrent period adjustment* to a subsequent *preliminary settlement statement.*

6.8.12 No *market participant* may submit a *notice of disagreement*, and any such *notice of disagreement* shall not be valid and any adjustment resulting from such *notice of disagreement* shall be void, if the *notice of disagreement*:

6.8.12.1 is submitted to the *IESO* after the time specified in 6.3.3, 6.3.5, 6.3.7, 6.3.14, 6.3.16, 6.3.18, and 6.3.25.2, as the case may be;

6.8.12.2 relates to an issue which falls outside the permitted scope of such *notice of disagreement* outlined in sections 6.8.2 or 6.8.3, as the case may be;

6.8.12.3 relates to a *final recalculated settlement statement*;

6.8.12.4 relates to a compliance and enforcement action described in section 6 of Chapter 3, or matters relating to section 3.5.6B, section 3.5.6C, section 3.5.6D, section 3.5.6G, section 3.5.9, section 3.8.1, section 3.8.2, or section 4.7E of Chapter 9, section 2.2B.2 of Chapter 7 or Appendix 7.6 of Chapter 7;

6.8.12.5 relates to a dispute referred to in section 2.1A.6A of Chapter 9;

6.8.12.6 relates to an adjustment made on a *settlement statement* reflecting a dispute outcome;

6.8.12.7 relates to a matter described in the processes outlined in section 10.4 of Chapter 6 and section 6C of Chapter 10;

6.8.12.8 relates to the calculation of:

a. the 5-minute *energy market* price for any *dispatch interval* in a given settlement hour;

b. the 5-minute *market price* for any class of *operating reserve* for any *dispatch interval* in a given *settlement hour*; or

c. the hourly Ontario energy price for a given *settlement hour*; or

6.8.12.9 relates to a matter which the *market participant* has already submitted a *notice of disagreement*, including in regards to an earlier *settlement statement*.

6.8.13 Subject to the processes outlined in section 10.4 of Chapter 6 and section 6C of Chapter 10, *market participants* that fail to submit a *notice of disagreement* in accordance with section 6.8 in regards to a *settlement statement* shall have no further recourse in regards to the amount of any *settlement amount* contained on such *settlement statement*.

6.8.14 Nothing in section 6.8.12 shall prevent a *market participant* from submitting, or the *IESO* from making a determination in regards to, a *notice of disagreement* that relates to the manner in which any of the elements noted in sections 6.8.12.8 have been applied for purposes of the calculation of the *market participant's* net *settlement amount.*

6.8.15 If a *market participant* disagrees with the *IESO*'s conclusion and action taken in accordance with section 6.8.9 or the *IESO* has not made its determination prior to the earlier of either (i) the date that is 23 months after the date on which the relevant *trading day* was first *invoiced*; or (ii) twelve months after the date the *notice of disagreement* was issued by the *market participant*, the *market participant* may pursue their disagreement through the dispute resolution procedure described in section 6.10.1. Additionally, if a *market participant* disagrees with an item or calculation on a *final settlement statement* or a *recalculated settlement statement*, which is either new and not set forth on an earlier *settlement statement* or differs from the same item or calculation set forth on an earlier *settlement statement* but such item or calculation is not identified as associated with an adjustment flag, the *market participant* may pursue their disagreement through the dispute resolution procedure described in section 6.10.1.

6.9 IESO Validation of Settlement Statements

6.9.1 Subject to section 6.9.2, if the *IESO* becomes aware of a possible error within an *IESO* system or *settlement process* that a *market participant* would not have reasonably been able to identify and address through section 6.8 and which may result in *settlement amounts* being calculated incorrectly, the *IESO* shall use the information available to the *IESO* to consider the possible error and take one of the following steps:

6.9.1.1 if the *IESO* concludes that no material adjustment or correction is required, it shall take no further action; and

6.9.1.2 if the *IESO* concludes that a material adjustment or correction is required, take one or more of the following actions:

a. if the correction is with respect to an item or calculation on a *preliminary settlement statement* and the *IESO* makes its determination prior to the issuance of the corresponding *final settlement statement*, the *IESO* shall adjust the corresponding *final settlement statement* accordingly;

b. if the correction is with respect to an item or calculation on a *preliminary settlement statement* and the *IESO* makes its determination after the issuance of the corresponding *final settlement statement*, the *IESO* shall make the adjustment on one or more *recalculated settlement statements*. For clarity, where the correction relates to a trading date prior to the *IESO* commencing the issuance of *recalculated settlement statements*, the *IESO* shall make the adjustment on a subsequent *preliminary settlement statement*; and

c. if the correction is with respect to an item or calculation on any other *settlement statement*, the *IESO* shall make the adjustment on one or more *recalculated settlement statement*.

6.9.2 Notwithstanding section 6.9.1 and commencing with *settlement amounts* which were invoiced or should have been invoiced on or after *RSS commencement date*, the *IESO* shall not take any action or make any correction under section 6.9 in regards to any *settlement amounts* which were invoiced, or should have been invoiced, more than 23 months before the day on which the *IESO* issues the *settlement statement* referred to in section 6.9.1.2. Notwithstanding the foregoing, where entitlement to a *settlement amount* is prescribed by *applicable law*, the *IESO* shall not take any action or make any correction under section 6.9 in regards to any *settlement amount* if a limitation period applicable to such *settlement amount* prescribed in *applicable law* has lapsed.

6.9.3 If the *IESO* does not make its determination before the date for issuing the any *settlement statements*, as applicable, the *IESO* shall issue such *settlement statements* without taking into account the error being considered.

6.9.4 Any changes required to be made in a *final settlement statement* or *recalculated settlement statement* as a result of the validation process described in this section 6.9 shall, subject to section 6.18.3, be included as:

6.9.4.1 a debit or credit in the *final settlement statement*, or

6.9.4.2 if the *IESO* has already issued the relevant *final settlement statement* prior to the determination of the required change, as an *adjustment period allocation,* to a *recalculated settlement statement,* or a subsequant *preliminary settlement statement* where the *notice of disagreement* relates to a *trading date* prior to the *IESO* commencing the issuance of *recalculated settlement statements,* issued for each affected *market participant*. If, after making all reasonable efforts to do so, the *IESO* cannot recover these amounts from or distribute these amounts to a former *market participant*, such amounts shall then be included as a c*urrent period adjustment* to a subsequent *preliminary settlement statement.*

6.9.5 If a *market participant* disagrees with the *IESO*'s conclusion and action taken in accordance with section 6.9.1.2, the *market participant* may pursue their disagreement through the *market participant* validation procedure described in section 6.8, or, if the adjustment is made on a *final recalculated settlement statement* or on an ad hoc *recalculated settlement statement* issued after the date when the sixth *recalculated settlement statement* is scheduled to be issued*,* through the dispute resolution procedure described in section 6.10.1.

6.9.6 Notwithstanding the foregoing, nothing in this section 6.9 limits the *IESO*'s ability to apply an adjustment related to matters described in section 6.8.12.4, including as a *current period adjustment* to a *preliminary settlement statement* issued more than two years after the *invoice* for the relevant *trading day* was issued.

6.10 Dispute Resolution

6.10.1 Subject to section 6.10.2, if a *market participant* wishes to initiate a dispute in regards to matters described in section 6.8.15, section 6.9.5, section 6.8.12.4, or in regards to a *final recalculated settlement statement,* it may submit the matter to the dispute resolution process set forth in section 2 of Chapter 3.

6.10.2 In regards to matters described in section 6.10.1, no *market participant* may submit a *notice of dispute*, and any such *notice of dispute* shall not be valid, if:

6.10.2.1 in regards to disputes pertaining to *settlement statements* other than a *final recalculated settlement statement,* the *notice of dispute* relates to a matter which, pursuant to section 6.8.2, section 6.8.3, or section 6.8.12, except for section 6.8.12.4, is not an item or calculation for which the the *market participant* is permitted to submit a *notice of disagreement*, unless the only reason that a *market participant* is not permitted to submit a *notice of disagreement* is because the new or adjusted item or calculation is not identified as associated with an adjustment flag;

6.10.2.2 in regards to disputes pertaining to a *final recalulated settlement statement,* the *notice of dispute* relates to a matter:

a. which does not differ in amount from the same item or calculation set forth on an earlier *settlement statement* corresponding to the same *trading day*;

b. is not an item or calculation which is new and not set forth on an earlier *settlement statement* corresponding to the same *trading day*;

c. is not an item or calculation which the *market participant* considers that there is an omission in such *settlement statement*; or

d. described in sections 6.8.12.5 to 6.8.12.9.

6.10.2.3 subject to section 2.5.1B of Chapter 3, the *notice of dispute* was submitted by the *market participant*:

a. in regards to matters described in section 6.8.15 where the *IESO* has made its determination, more than twenty *business days* after either the *IESO* notifies the *market participant* in accordance with section 6.8.9.1 or issues the relevant *settlement statement* in accordance with section 6.8.9.2, as the case may be;

b. in regards to matters described in section 6.8.15 where the *IESO* has not made its determination, prior to the date referred to in section 6.8.15;

c. in regards to matters described in section 6.9.5 where the adjustment is made on an ad hoc *recalculated settlement statement* issued after the date when the sixth *recalculated settlement statement* is scheduled to be issued*,* more than twenty *business days* after the *IESO* issues the ad hoc *recalculated settlement statement;*

d. in regards to disputes pertaining to a *final recalculated settlement statement*, more than twenty *business days* after the *IESO* issues the *final recalculated settlement statement*;

e. in regards to matters described in section 6.8.12.4, except for a compliance and enforcement action described in section 6 of Chapter 3, more than twenty *business days* after the *IESO* issues the *settlement statement* containing the amounts being disputed;

f. in regards to a compliance and enforcement action described in section 6 of Chapter 3, outside of the applicable timeline set forth in section 2.5.1A of Chapter 3; and

g. in regards to an item or calculation on a *final settlement statement* or a *recalculated settlement statement*, which is either new and not set forth on an earlier *settlement statement* or differs from the same item or calculation set forth on an earlier *settlement statement* but such item or calculation is not identified as associated with an adjustment flag, more than twenty *business days* after the *IESO* issues the *settlement statement* containing the amounts being disputed.

6.10.3 Following the resolution of a dispute, the *IESO* shall arrange to have the *dispute outcome* carried out as soon as is reasonably practicable following the resolution of the dispute, subject to the availability of data and of the *IESO's* resources.

6.10.4 To implement a *dispute outcome*, the *IESO* shall:

6.10.4.1 for the *market participant* that originally filed the *notice of dispute* that resulted in the *dispute outcome*, reflect the amounts to be debited or credited in accordance with the following:

a. if the dispute is resolved prior to the issuance of the *final recalculated settlement statement* and the *IESO* has sufficient time to implement the *dispute outcome* on a *recalculated settlement statement*, the *IESO* shall reflect such credits or debits on the next scheduled *recalculated settlement statement*; or

b. if the dispute is resolved after the issuance of the *final recalculated settlement statement,* the dispute relates to a *trading day* prior to the *IESO* commencing the issuance of *recalculated settlement statements,* or the *IESO* does not have sufficient time to implement the *dispute outcome* on the *final recalculated settlement statement*, the *IESO* shall reflect such credits or debits on a subsequent *preliminary settlement statement* issued for the *market participant*.

6.10.4.2 ensure any credit adjustment made to such *market participant*, being a refund of payments already made, shall include interest at the *default interest rate* from the date the overpayment was received to the time that the repayment is credited to the relevant *market participant settlement account*;

6.10.4.3 arrange to have all net adjustments for each *market participant*, and any interest on such net adjustments, placed into the *IESO adjustment account*; and

6.10.4.4 for any other *market participant* affected by the *dispute outcome*, reflect the incremental dollar amount determined in section 6.10.4.1 as a debit or credit in accordance with the following:

a. if the dispute is resolved prior to the issuance of the *final recalculated settlement statement* and the *IESO* has sufficient time to implement the *dispute outcome* on a *recalculated settlement statement*, the *IESO* shall reflect such credits or debits as an *adjustment period allocation* on the next scheduled *recalculated settlement statement.* If, after making all reasonable efforts to do so, the *IESO* cannot recover these amounts from or distribute these amounts to a former *market participant*, such amounts shall then be included as a c*urrent period adjustment* to a subsequent *preliminary settlement statement;*or

b. if the dispute is resolved after the issuance of the *final recalculated settlement statement,* the dispute relates to a *trading day* prior to the *IESO* commencing the issuance of *recalculated settlement statements,* or the *IESO* does not have sufficient time to implement the *dispute outcome* on a *recalculated settlement statement*, the *IESO* shall reflect such credits or debits as a c*urrent period adjustment* on a subsequent *preliminary settlement statement* issued for the *market participant.*

6.10.4.5 Notwithstanding the section 6.10.4.1(a) and 6.10.4.4(a), where *dispute outcome* requires an adjustment within a specified time period and the next scheduled *recalculated settlement statements* follows such time period, the *IESO* shall issue an ad hoc *recalculated settlement statements* to reflect such adjustments within the required timeframe.

6.11 Responsibility of the IESO

6.11.1 In carrying out its *settlement* responsibilities, the *IESO* shall operate in a non-discriminatory manner.

6.11.2 The *IESO* shall not be a counter-party to any trade transacted through the *real-time markets*.

6.12 Settlement Invoices

6.12.1 Unless the *IESO* has invoked the estimated *invoice* procedure pursuant to section 6.3.27, each *invoice* issued by the *IESO* to a *market participant* shall be based on all of the *settlement statements* issued to the *market participant* since their last *invoice* was issued except for any that may pertain to the next *billing period*, as more particularly described in the applicable *market manual*. In each *invoice*, other than an estimated *invoice* issued pursuant to section 6.3.27:

6.12.1.1 each line item shall correspond to a distinct commodity or service bought or sold over the *billing period*; and

6.12.1.2 the *charge type* appearing on the *invoice* shall allow *invoice* line items to be cross-referenced to the relevant *settlement statements.*

6.12.2 The *IESO* shall, on the days specified in accordance with sections 6.3.8 and 6.3.19 or, where applicable, on either of the dates referred to in section 6.3.27 or section 6.3.33, issue an *invoice* to each *market participant* showing:

6.12.2.1 the dollar amounts which are to be paid by or to the *market participant*, according to *settlement statements* as specified in section 6.12.1 or as estimated pursuant to section 6.3.27;

6.12.2.2 the *market participant payment date* by which such amounts (if any) are to be paid by the *market participant* no later than the *close of banking business* (of the bank at which the *IESO settlement clearing account*);

6.12.2.3 the *IESO payment date* by which the *IESO* is to make payments (if any) to the *market participant* no later than the *close of banking business* (of the bank at which the *market participant settlement account* is held); and

6.12.2.4 details of the *IESO settlement clearing account*, including the bank name, account number and *electronic funds transfer* instructions, to which any amounts owed by the *market participant* are to be paid in accordance with section 6.12.2.2.

6.12.3 *Invoices* shall be considered issued to *market participants* when issued by the *IESO* in accordance with the applicable *market manuals*.

6.12.4 It is the responsibility of each *market participant* to notify the *IESO* if it fails to receive an *invoice* on the date specified for the issuance of such *invoice* accordance with sections 6.3.8 and 6.3.19 or, where applicable, on either of the dates referred to in section 6.3.27 or section 6.3.33. Each *market participant* shall be deemed to have received its *invoice* on the relevant date specified in

accordance with sections 6.3.8 and 6.3.19 or, where applicable, on either of the dates referred to in section 6.3.27 or section 6.3.33*,* unless it notifies the *IESO* to the contrary.

6.12.5 In the event that a *market participant* notifies the *IESO* that it has failed to receive an *invoice* on the relevant date specified in accordance with sections 6.3.8 and 6.3.19 or, where applicable, on either of the dates referred to in section 6.3.27 or section 6.3.33*,* the *IESO* shall re-send the appropriate *invoice* and the *invoice* shall be considered received on the date the re-sent *invoice* is sent to the *market participant.*

6.13 Payment of Invoices

6.13.1 Subject to section 6.13.2, each *market participant* shall pay the full net *invoice* amount by the *market participant payment date* specified in accordance with section 6.3.9 and 6.3.20 or, where applicable, determined in accordance with any of sections 6.3.27, 6.3.31 and 6.3.33, regardless of whether or not the *market participant* has initiated or continues to have a dispute respecting the net amount payable.

6.13.2 A *market participant* may pay at an earlier date than the *market participant payment date* specified in accordance with section 6.3.9 and 6.3.20 or, where applicable, determined in accordance with any of sections 6.3.27, 6.3.31, and 6.3.33 in accordance with the following:

6.13.2.1 notification must be given to the *IESO* before submitting such prepayment or before converting an existing overpayment by the *market participant* into a prepayment;

6.13.2.2 the prepayment notification shall specify the dollar amount prepaid;

6.13.2.3 a prepayment shall be made by the *market participant* into the *IESO prepayment account* designated by the *IESO*;

6.13.2.4 on any *market participant payment date,* the *IESO* may initiate the transfer of necessary funds from the *IESO prepayment account* to the *IESO settlement clearing account* to discharge, up to the amount of the prepayment, that *market participant*'s outstanding payment obligations arising in relation to that *market participant payment date;* and

6.13.2.5 subject to section 5.6.3 of Chapter 2, and notwithstanding section 4.18.1.2 of Chapter 8, funds held in an *IESO prepayment account* on behalf a *market participant* may be applied by the *IESO* to any outstanding

financial obligations of that *market participant* to the *IESO* for transactions carried out in the *IESO-administered markets.*

6.13.3 With respect to *transmission services charges*, the *IESO* may instruct the bank where the *IESO settlement clearing account* is held to debit the *IESO settlement clearing account* and transfer to the relevant *transmitter's transmission services settlement account* sufficient funds to pay in full the *transmission services charges* falling due to that *transmitter* on any *IESO payment date* specified in accordance with sections 6.3.11 and 6.3.22 or, where applicable, determined in accordance with any of sections 6.3.27, 6.3.31, and 6.3.33.

6.13.4 With respect to the *IESO administration charge*, the *IESO* may instruct the bank where the *IESO settlement clearing account* is held to debit the *IESO settlement clearing account* and transfer to the relevant *IESO* operating account sufficient funds to pay in full the *IESO administration charge* falling due on any *IESO payment date* specified in accordance with sections 6.3.11 and 6.3.22 in priority to any other payments to be made on that *IESO payment date* or on subsequent days out of the *IESO settlement clearing account.*

6.13.5 With respect to the smart metering charge, the *IESO* may instruct the bank where the *IESO settlement clearing account* is held to debit the *IESO settlement clearing account* and transfer to the relevant *IESO* operating account only those funds that were received in the *IESO settlement clearing account* in payment of the smart metering charge. The smart metering charge is the fee approved by the *OEB* to recover costs incurred by the *IESO* solely as a result of the *IESO* acting as the Smart Metering Entity and its responsibilities related to the smart metering initiative.

6.13.6 The *IESO* shall, on the *IESO payment date* specified in accordance with sections 6.3.11 and 6.3.22 or, where applicable, determined in accordance with any of sections 6.3.27, 6.3.31, and 6.3.33, determine the amounts available in the *IESO settlement clearing account* for distribution to *market participant*s or the *forecasting entity*, and shall, if necessary, borrow funds in accordance with the provisions of section 6.16 if necessary to enable the *IESO settlement clearing account* to clear no later than 11:00 am on the *IESO payment date*.

6.14 Funds Transfer

6.14.1 All payments by *market participant*s in respect of *settlement* matters shall be made to the *IESO settlement clearing account* via *electronic funds transfer* and shall be effected by the dates and times specified in this Chapter.

6.14.2 All payments by the *IESO* to *market participants* in respect of settlement matters shall be made to each *market participant's market participant settlement account* or to each *transmitter's transmission services settlement account* via *electronic funds transfer* and shall be effected by the dates and times specified in this Chapter.

6.14.3 In the event of failure of any *electronic funds transfer* system affecting the ability of either a *market participant* or the *IESO* to make payments, the affected party shall arrange for alternative means of payment so as to ensure that payment is effected by the dates and times specified in this Chapter.

6.14.4 No *market participant* shall include in any *electronic funds transfer* amounts attributable to more than one *invoice* or prepayment, unless such *electronic funds transfer* is in such form as may be specified in the applicable *market manual.*

6.14.5 The *IESO* shall be entitled to and shall rely on the information contained in or accompanying an *electronic funds transfer* received pursuant to section 6.14.4 for the purpose of allocating the aggregate amount of an *electronic funds transfer* referred to in that section and, notwithstanding section 13 of Chapter 1:

6.14.5.1 the *IESO* shall not be liable to any person in respect of the allocation of:

a. the aggregate amount of an *electronic funds transfer* when effected in accordance with such information or with section 6.14.6.1; or

b. the amount of any associated overpayment or underpayment effected in accordance with section 6.14.6.2; and

6.14.5.2 the *market participant* providing the *IESO* with such information shall indemnify and hold harmless the *IESO* in respect of any claims, losses, liabilities, obligations, actions, judgements, suits, costs, expenses, disbursements and damages incurred, suffered, sustained or required to be paid, directly or indirectly, by, or sought to be imposed upon, the *IESO* arising from the allocation by the *IESO* of:

a. the aggregate amount of an *electronic funds transfer* when effected in accordance with such information or with section 6.14.6.1; or

b. the amount of any associated overpayment or underpayment effected in accordance with section 6.14.6.2.

6.14.6 Where a *market participant* that initiates an *electronic funds transfer* to which section 6.14.4 applies fails to provide the information contained in or

accompanying an *electronic funds transfer* referred to in section 6.14.4, the *IESO* shall allocate:

6.14.6.1 the aggregate amount of the *electronic funds transfer;* and

6.14.6.2 the entire amount of any associated overpayment or underpayment,

to that *market participant*.

6.15 Confirmation Notices

6.15.1 At the end of each calendar month, the *IESO* shall issue a *monthly confirmation notice* to each *market participant* which shall contain statements of the amounts received from or paid out to the *market participant* on each *market participant payment date* and *IESO payment date* in that month and any payments outstanding.

6.16 Payment Default

6.16.1 Subsequent to the *close of banking business* (of the bank at which the *IESO settlement clearing account* is held) on the *market participant payment date* referred to in accordance with section 6.3.9 and 6.3.20 or, where applicable, determined in accordance with any of sections 6.3.27, 6.3.31, and 6.3.33*,* the *IESO* shall ascertain if the full amount due by any *market participant* has been remitted to the *IESO settlement clearing account*.

6.16.2 A *market participant* shall notify the *IESO* immediately if it becomes aware that a payment for which it is responsible will not be remitted to the *IESO settlement clearing account* on time and shall provide the reason for the delay in payment.

6.16.3 If the full amount due by a *market participant* has not been remitted after accounting for any prepayments made by the *market participant* pursuant to section 6.13.2**,** the provisions of section 6.3 of Chapter 3 shall apply and *default interest* shall accrue on all amounts outstanding.

6.16.4 If the *market participant's invoice* includes a *settlement amount* owing for the smart metering charge under section 6.13.5 and the *market participant*

a. fails to remit the full *invoice* amount due by the *market participant payment date*; and

b. does not direct the *IESO* how to apportion the payment between the smart metering charge and all other *settlement amounts* on the *invoice* prior to the *IESO payment date*, the *IESO* shall allocate the payment made by the

market participant first to satisfying any *settlement amounts* due under the *market rules* before being applied to the smart metering charge.

6.16.5 The *IESO* shall be authorized to borrow short-term funds to clear the credits in any settlement cycle only if the following conditions are met:

6.16.5.1 there are insufficient funds remitted into the *IESO settlement clearing account* or *TR clearing account* to pay all applicable *market creditors* due for payment from the funds in the *IESO settlement clearing account* or *TR clearing account,* and clear the *IESO settlement clearing account* or *TR clearing account* on a given *IESO payment date*, due to:

a. payment default by one or more *market participants* in the *real-time markets*; or

b. the circumstances referred to in section 4.19.2 or 4.19.6 of Chapter 8;

6.16.6 If the *IESO* borrows short-term funds pursuant to section 6.16.5, it shall recover this borrowing:

6.16.6.1 where the insufficient funds were due to a payment default referred to in section 6.16.5.1 (a) by taking all steps against the *defaulting market participant* as provided for in these *market rules,* including, if necessary, by imposing the *default levy* in accordance with section 8 of Chapter 2; or

6.16.6.2 where the insufficient funds were due to the circumstances referred to in section 6.16.5.1 (b), in the manner referred to in sections 4.19.3 and 4.19.5 of Chapter 8 and then, if necessary, by recovering from *market participants* proportionately based on *transmission service charges* paid during all intervals and *settlement hours* within the *energy market billing period* in which the *IESO* invoices the *market participants*.

6.16.6.2.1 Where a *market participant* has paid provincial *transmission service charges*, recovery pursuant to section 6.16.6.2 shall be recovered individually, proportionate to the quantities of *energy* withdrawn at all *RWMs* excluding *intertie metering points* during all intervals and *settlement hours* within the *energy market billing period* in which the *IESO* invoices the *market participants*, in accordance with section 6.16.6.3

6.16.6.2.2 Where a *market participant* has paid export *transmission service* charges, recovery pursuant to section 6.16.6.2 shall be recovered individually, proportionate to the quantities of *energy* withdrawn at all *intertie metering points* during all intervals and *settlement hours* within the *energy market*

billing period in which the *IESO* invoices the *market participants*, in accordance with section 6.16.6.3

6.16.6.3 The portion of any short-term funds borrowed by the *IESO* to be recovered from *market participant* 'k' in the current *energy market billing period* shall be calculated as follows:

For market participants that have paid provincial transmission service charges in the current energy market billing period:

$$TRCAC_k = TRCAD_L \times \sum_H{}^{M,T} [(AQEW_{k,h}{}^{m,t}) / \sum_{K,H}{}^{M,T} (AQEW_{k,h}{}^{m,t})$$

For market participants that have paid export *transmission service charges* in the current energy market billing period**:**

$$TRCAC_k = TRCAD_E \times \sum_H{}^{I,T} [(SQEW_{k,h}{}^{i,t}) / \sum_{K,H}{}^{I,T} (SQEW_{k,h}{}^{i,t})]$$

Where:

$$TRCAD_L = (\sum_K TD_C / \sum_K TD_{C,C1}) \times TRCAR$$

$$TRCAD_E = (\sum_K TD_{C1} / \sum_K TD_{C,C1}) \times TRCAR$$

TRCAR = the total dollar value of TR shortfall recovery from the *TR clearing account* authorized by the *IESO Board* in the current *energy market billing period*

6.16.7 If there are insufficient funds remitted into the *IESO settlement clearing account* to pay all *market creditors* due for payment from the funds in the *IESO settlement clearing account,* and clear the *IESO settlement clearing account* on a given *IESO payment date* due to default by one or more *market participant*s or to the circumstances referred to in section 6.16.5.1 (b), the *IESO* shall borrow funds in accordance with section 6.16.5 in order to clear the *IESO settlement clearing account* no later than the *close of banking business* (of the bank at which the *IESO settlement clearing account* is held) on that *IESO payment date*.

6.16.8 If the *IESO* has exhausted credit availability contemplated by section 6.16.5, then the *IESO* shall pay *real-time market creditors* on a pro rata basis in proportion to the amounts owed to each *market creditor*. Any amounts that remain owing to *real-time market creditors* shall bear interest at the *default interest rate* until paid.

6.16.9 Upon receipt of any payments by the *IESO*, either from or on the behalf of one or more *defaulting market participants* including any *prudential support* held by the *IESO*, or on behalf of *non-defaulting market participants* pursuant to a *default*

levy, the *IESO* shall first repay all existing lines of credit and other banking facilities, and following repayment of such lines of credit and banking facilities, the *IESO* shall then repay on a pro-rata basis all *market creditors* owed amounts pursuant to section 6.16.8.

6.17 Payment Errors, Adjustments, and Interest

6.17.1 If a *market participant* receives an overpayment on any *IESO payment date:*

6.17.1.1 the *market participant* shall notify the *IESO* of such overpayment within two *business days* of the overpayment or immediately as soon as the *market participant* thereafter becomes aware of the situation;

6.17.1.2 if the *IESO* determines or becomes aware of the overpayment prior to being notified by the *market participant*, the *IESO* shall notify the *market participant* of the overpayment;

6.17.1.3 the *market participant* receiving the overpayment shall, until it has refunded the overpayment to the *IESO*, be deemed to be holding the amount of such overpayment in trust for any other *market participant*s that may have been underpaid in consequence of such overpayment, pro rata to the amount of the underpayment;

6.17.1.4 the *IESO* shall be entitled to treat the overpayment and any interest accruing thereon as an unpaid amount to which section 6.16 applies; and

6.17.1.5 if not repaid fully within 2 *business days* of receiving the overpayment, the unpaid amount of any overpayment shall bear interest at the *default interest rate* from the date of overpayment until the date on which repayment is credited to the *IESO's* relevant *settlement account*.

6.17.2 The *IESO* shall be responsible for identifying any *market participant*s who have been underpaid as a result of an overpayment to another *market participant*.

6.17.3 The *IESO* shall pay any underpaid *market participant* for the amounts of their underpayment, including interest calculated from the date the *market participant* should have been paid, as soon as practicable following repayment by the overpaid *market participant*.

6.17.4 If a *market participant* has overpaid the *IESO* on any *market participant* payment date:

6.17.4.1 the *market participant* shall notify the *IESO* of such overpayment within two *business days* or immediately as soon as the *market participant* thereafter becomes aware of the situation;

6.17.4.2 if the *IESO* determines or becomes aware of such overpayment prior to being notified by the *market participant*, the *IESO* shall notify the *market participant* accordingly;

6.17.4.3 the *market participant* may request that the overpaid amount be either refunded or treated as a prepayment pursuant with section 6.13.2; and

6.17.4.4 any related administration and transaction costs incurred by the *IESO* in managing and resolving the over-payment shall be charged to the account of the *market participant* involved.

6.17.5 If the *IESO* underpays any *market participant* on any *IESO payment date*:

6.17.5.1 the *market participant* shall notify the *IESO* of such underpayment within two *business days* or immediately as soon as the *market participant* thereafter becomes aware of the situation;

6.17.5.2 if the *IESO* determines or becomes aware of the underpayment prior to being notified by the *market participant*, the *IESO* shall notify the *market participant* accordingly; and

6.17.5.3 the *IESO* shall use all reasonable endeavours to promptly correct any underpayments, including interest thereon at the *default interest rate*.

6.17.6 If the *IESO* is underpaid by a *market participant* on any *market participant payment date,* the provisions of section 6.16 or of section 4.20 of Chapter 8 shall apply.

6.17.7 If the *IESO* borrows funds in accordance with section 6.16.5 because a payment due from a *market participant* was received too late to be credited to the *IESO settlement clearing account* by *close of banking business* (of the bank at which the *IESO settlement clearing account* is held) on the *market participant payment date* when such payment was due, then such remittance when it does arrive shall be used to repay the borrowed funds. Any such late payments shall be charged the *Canadian prime interest rate* plus 2%.

6.17.8 If the *IESO* holds or has under its control after five *business days* from receipt in the *IESO settlement clearing account* amounts which it ought properly to have paid to *market participant*s, such *market participant*s shall be entitled to interest on such amounts at the *default interest rate* from the date on which the *IESO*

commenced to improperly hold or have such amounts under its control to the date on which such amounts are paid to the relevant *market participants.*

6.17.9 Monies in the *IESO settlement account*s at the end of each year which have been earned from interest on funds in the *IESO settlement account*s and which are not attributable to any incomplete *settlement process* or outstanding *settlement* dispute shall be used to off-set the *IESO administration charge* in the following year.

6.17.10 Where an amount is payable to a former *market participant* as a result of a *settlement* adjustment, the *IESO* shall endeavor to distribute the amount as specified in the applicable *market manual*. If the *IESO* cannot distribute the amount to the former *market participant* as specified in the applicable *market manual*, such amount shall be used to offset the *IESO administration charge*.

6.18 Settlement Financial Balance/Maximum Amount Payable by IESO

6.18.1 The *IESO* shall provide and operate a *settlement* control process to monitor the financial balance of the calculated charges and payments so as to ensure that, subject to section 6.18.3:

6.18.1.1 for *hourly market* transactions, other than transactions in the *TR market,* the sum of all payments for all *market creditors* involved in such *hourly market* transactions exactly equal the sum of all charges for *market debtors* involved in such *hourly market* transactions for each *trading day* of a *billing period*; and

6.18.1.2 for all other transactions, other than transactions in the *TR market* including monthly charges, adjustment charges and payments, the sum of all payments to *market creditors* of those transactions exactly equals the sum of all charges to *market debtors* of those transactions for each *billing period*.

6.18.2 Subject to the provisions of section 6.16, the *IESO* shall not be liable to make payments in excess of the amount it receives for transactions in the *real-time markets*.

6.18.3 If there is an aggregate imbalance for all transactions for a given *trading day* or *billing period,* the *IESO* shall, in accordance with section 6.18.4 or by such other means as the *IESO* determines appropriate, recover that portion of the imbalance that arises by virtue of the rounding of *settlement amounts* or of an adjustment to

the *settlement statement* of one *market participant* that is too small to be reflected in corresponding *settlement statement* of other *market participants* provided that:

6.18.3.1 the manner of calculation of that portion of the imbalance can be evidenced in a manner satisfactory for purposes of the audit referred to in section 6.19; and

6.18.3.2 that portion of the imbalance has accumulated to an amount which is sufficient to permit recovery.

6.18.4 The *IESO* may recover the portion of an aggregate imbalance referred to in section 6.18.3 by means of an adjustment to a *settlement statement* applied:

6.18.4.1 to *market participants* to whom *hourly uplift* may be allocated pursuant to these *market rules*;

6.18.4.2 in the same manner as *hourly uplift;* and

6.18.4.3 in respect of all *settlement hours* of the last day of the *billing period* in which the portion of such aggregate imbalance is determined to arise and be recoverable pursuant to section 6.18.3.

6.19 Audit

6.19.1 The audit of *settlement* functions referred to in this section 6.19 shall serve to examine and evaluate compliance with management control objectives and operational effectiveness of *settlement process*es and procedures.

6.19.2 The audits referred to in section 6.19.3 shall be performed by an external, independent auditing firm.

6.19.3 Unless otherwise directed by the *IESO Board*, the *IESO* shall every two years, on the anniversary of the *market commencement date*, direct a comprehensive external audit on the *settlement process*es and procedures. The audit shall include the following tasks:

6.19.3.1 gauge the performance of the *settlement process* in meeting the objectives of these *market rules;*

6.19.3.2 review the accuracy and timeliness of the production of *settlement statements*, including *settlement* calculations and financial allocations;

6.19.3.3 review the accuracy and timeliness of the production of *invoice*s and supporting market and system information;

6.19.3.4 review the *reliability* and integrity of the market and system operational data used in the *settlement process*es and procedures;

6.19.3.5 review the *reliability* and security of the information technology system infrastructure used to measure, validate, classify, compute and report *settlement* information;

6.19.3.6 review the adequacy of *settlement processes* and procedures to safeguard *confidential information*; and

6.19.3.7 review the adequacy and effectiveness of risk management controls of the *settlement process*es and tools, including the effectiveness of the *disaster recovery plan.*

6.19.4 *Settlement statements*, financial *settlement* records and any documentation pertaining to the *IESO's settlement* activities shall, subject to sections 2.11.1 to 2.11.3, be kept in secure storage for a period of at least seven years and made available for auditing purposes.

6.19.5 An audit report shall be prepared by the auditors in respect of each audit conducted pursuant to this section 6.19 and shall be commissioned on the basis that the audit report must be provided to the *IESO* within one month after completion of the audit activities.

6.19.6 Each audit report prepared pursuant to this section 6.19 shall be made available to a *market participant* upon request, subject to such measures as may be required to be taken to safeguard any *confidential information* contained in such audit report.

6.20 Settlement Accounts

6.20.1 The *IESO* shall establish and maintain the *settlement accounts* described in this section 6.20 for the operation of its *settlement* and billing systems.

6.20.2 The *IESO* shall obtain lines of credit and other banking facilities it deems necessary for the operation of the *settlement accounts* described in this section 6.20, which lines of credit and other banking facilities shall not exceed an aggregate amount approved by the *IESO Board*.

6.20.3 The *IESO* may establish *settlement accounts* in addition to those referred to in this section 6.20 as may be necessary to implement the *settlement* and billing processes outlined in this Chapter. *Market participant*s shall be notified 60 *business days* prior to any such additional *settlement accounts* becoming *operational*.

6.20.4 The *IESO* shall open and maintain the *IESO settlement clearing account* as a single bank account to and from which all *settlement* payments shall be made in accordance with the provisions of this Chapter and the details of which shall appear in the *invoice*s sent by the *IESO* to *market participant*s as provided in section 6.12.2.4**.**

6.20.5 The *IESO* shall open and maintain the *IESO adjustment account*, which *account* shall operate as follows:

6.20.5.1 the *IESO adjustment account* shall be a single bank account established to receive and disburse payments related to penalties, damages, fines and payment adjustments arising from resolved *settlement* disputes, and to reimburse the *IESO* for any associated costs or expenses;

6.20.5.2 any amounts paid into the *IESO adjustment account* by *market participant*s shall first be applied to reimburse the *IESO* in respect of any costs or expenses described in section 6.20.5.1 which it has or will incur. Any remaining amount shall be credited to the *IESO adjustment account;* and

6.20.5.3 the *IESO Board* shall review, at least annually, the allocation of any credit balance of the *IESO adjustment account*, and may:

a. establish an amount to be retained in the *IESO adjustment account*;
b. direct that some or all of the credit balance be applied to special education projects or initiatives; and/or
c. direct that some or all of the balance be distributed to *market participants* on a basis to be determined by the *IESO board*.

6.20.6 The *IESO* shall open and maintain the *IESO prepayment account,* which *account* shall operate as follows:

6.20.6.1 the *IESO prepayment account* shall be a bank account established for *market participants* to deposit prepayments at an earlier date than the specified *market participant payment date*; and

6.20.6.2 the arrangements for making the prepayment and transferring funds from the *IESO prepayment account* to the *IESO settlement clearing account* shall be in accordance with the provisions of section 6.13.2.

6.20.7 The *IESO* shall open and maintain the *TR clearing account*, which *account* shall operate in the manner described in sections 4.18 and 4.19 of Chapter 8.

6.20.8 Unless otherwise specified, the *IESO* shall recover all banking costs reasonably incurred in opening and operating the *IESO's settlement accounts* through the *IESO administration charge.*

6.20.9 The *IESO* shall maintain its *settlement accounts* at a bank or financial institution in the Province of Ontario approved by the *IESO Board*.

6.20.10 Each *transmitter* shall be required to open and maintain a *transmission services settlement account* at a bank named in a Schedule to the *Bank Act*, S.C. 1991, c. 46, located in the Province of Ontario, and capable of performing electronic funds transfers.

6.20.11 Each *transmitter* shall inform the *IESO* of all applicable information required for the *IESO* to make payment into the *transmitter's transmission services settlement account*.

6.20.12 Each *market participant* shall be required to open and maintain a *market participant settlement account* at a bank named in a Schedule to the *Bank Act*, S.C. 1991, c. 46, located in the Province of Ontario, and capable of performing electronic funds transfers.

6.20.13 Each *market participant* shall inform the *IESO* of all applicable information required for the *IESO* to make payment into the *market participant's market participant settlement account*.

6.20.14 The *settlement accounts* referred to in this section 6.20 may be changed or closed as follows:

6.20.14.1 the *IESO* may change the bank or the details of any of its *settlement accounts*, on the condition that the bank or financial institution is reasonably acceptable to the *IESO Board* and that all *market participant*s are notified by the *IESO* in writing at least 60 *business days* before the change takes effect; and

6.20.14.2 any *transmitter* or *market participant* may change its bank or the details of its *settlement account*, on the condition that the *IESO* is notified in writing at least 60 *business days* before the change takes effect.

Exhibit "O"

Chapter 11 of the IESO Market Rules issued November 29, 2023

Exhibit "O"

to the Affidavit of Robin Doolittle

Sworn before me on October 29, 2025, in accordance with O. Reg. 431/20, Administering Oath or Declaration Remotely



Commissioner for Taking Affidavits
(or as may be)

October 29, 2025

Keith Edward Hickey, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.

Expires June 24, 2027.

Market Rules

Chapter 11
Definitions

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Document Control

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Distribution List

Name	**Organization**

Table of Contents

1. Definitions 1

1. Definitions

Rule Notes:

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In the market rules:

actual exposure means, in respect of a given *market participant*, the amount calculated at any given time by the *IESO* for that *market participant* pursuant to section 5.5 of Chapter 2;

adequacy means the ability of the *electricity system* to supply electrical demand and *energy* requirements at all times, taking into account scheduled and unscheduled *outages* of equipment or components;

adjustment period allocation refers to a means of allocating post-final adjustments to *settlement amounts.* This allocation is based on *market participant* activity in the *energy market* during the event that is the subject of the originating *settlement* adjustment;

administrative price means a price established by the *IESO* in the circumstances referred to and in accordance with section 8.4A of Chapter 7;

advance approval means *IESO* approval of a *planned outage* before the scheduled start date of the *planned outage*. *Advance approval* includes *quarterly advance approval, weekly advance approval, three-day advance approval* and *one-day advance approval*;

affiliate, with respect to a corporation, has the meaning ascribed thereto in the *Business Corporations Act* (Ontario);

amend, in relation to the *market rules*, means any change to the *market rules*, whether by amendment, alteration, addition or deletion;

amendment submission has the meaning ascribed thereto in section 4.2.4 of Chapter 3;

ancillary service provider means a person who provides an *ancillary service*;

ancillary service means services necessary to maintain the *reliability* of the *IESO-controlled grid*, including, but not limited to, *regulation*, *black start capability*, *voltage control*, reactive power, *operating reserve* and any other such services established by the *market rules*;

applicable law means all laws, regulations, other statutory instruments and rules and other documents of a legislative nature which apply to the *IESO* or to *market participants*, and all

orders of a government, governmental body, authority or agency having jurisdiction over the *IESO* or a *market participant* including, but not limited to, any *licence* issued to the *IESO* or a *market participant*;

applicant has the meaning ascribed thereto in section 2.5.1 of Chapter 3;

application for authorization to participate means the form *published* by the *IESO* and by which a person may apply for authorization to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid*;

Arbitration Act, 1991 means the Arbitration Act, 1991, S.O. 1991, c. 17;

arbitrator means a qualified person appointed pursuant to section 2.7 of Chapter 3 to arbitrate a dispute;

area control error or *ACE* means the instantaneous difference between actual and scheduled interchange, taking into account the effects of frequency bias;

attended means regularly staffed on a twenty-four hours a day, seven days a week basis;

auction capacity means an amount in megawatts of electricity available to be provided to the *IESO-controlled grid*, by *capacity market participants* in association with a *capacity auction*;

auction period means, with respect to a *capacity auction,* the length of time commencing with the opening of the window during which the IESO receives *capacity auction offers*, and finishing at the time at which the *IESO publishes* auction results;

authority center means, in respect of a *facility*, an *attended* location at which indirect operational control of the *facility* is effected;

automatic generation control or *AGC* means the process that automatically adjusts the output from a *generation facility* or an *electricity storage facility* that is providing *regulation;*

automatic voltage regulation or *AVR* means the process that automatically adjusts the reactive output of a *generation unit, electricity storage unit,* or synchronous condenser to maintain the *unit* terminal voltage within a pre-determined range;

availability de-rating factor means, in respect of an *obligation period*, a value which is assigned to a *capacity auction resource,* as determined in accordance with the applicable *market manual.*

availability window means the hours in an *obligation period* during which *capacity auction resources* are required to be available to provide *auction capacity*;

basecase means a model of electrical components of the *IESO-controlled grid* and *neighbouring electricity systems.* Such components may include but are not limited to transformers, *generation facilities, electricity storage facilities,* and transmission lines, and includes the steady-state, dynamic and short circuit attributes of each component where applicable.

BES exception applicant means (i) a *market participant* who owns *IESO controlled-grid* elements or *facilities* who applies to the *IESO* for a *BES exception*; or (ii) a *connection applicant* who applies to the *IESO* for a *BES exception*;

BES exception request means an application for the approval, amendment, termination, or transfer of a *BES exception* pursuant to section 3.2B of Chapter 5;

bid means a statement of the quantities of a commodity that a buyer will purchase at different *market price* levels for that commodity in the *real-time market* or the *procurement market*;

bidding limit means, in respect of a given *TR participant*, the amount calculated by the *IESO* for that *TR participant* in accordance with section 4.14.1 of Chapter 8;

billing period means, in respect of the purchase or sale of *TRs* in a round of a *TR auction,* a period of a *trading week,* in respect of the *real-time markets* and the *settlement* of amounts owing to *TR holders* under section 4.4.1 of Chapter 8, a period of a calendar month;

black start capability means the capability of a *generation facility* to start without an outside electrical supply so as to be used to energize a defined portion of the *IESO-controlled grid*;

boundary entity means an entity designated and maintained by the *IESO* for the purpose of energy trading, and which represents the capacity of one or more resources, including but not limited to *generation facilities* or *load facilities*, located at a point or points external to the *IESO control area* which a *market participant* is entitled to inject into or withdraw from the *IESO-controlled grid* and which shall be deemed to be located in an *intertie zone* in accordance with section 2.2.7.2 of Chapter 7;

bulk electric system exception or *BES exception* is an exception from compliance with the requirements of *NERC reliability standards* relating to elements or *facilities* connected to the *IESO controlled-grid* in accordance with the Ontario-adapted *NERC* procedure for processing *BES exceptions;*

business day means any day other than a Saturday, a Sunday or a holiday as defined in section 88 of the *Legislation Act* and, where expressed by reference to the jurisdiction of a *market participant* other that the Province of Ontario, means any day other than a Saturday, a Sunday or a day on which banks are authorized or required to be closed in the jurisdiction of that *market participant*;

buying market participant means a *market participant* that is purchasing *energy* under a *physical bilateral contract*;

called capacity export means an *energy* export from the *IESO control area* that is supported by the capacity of a *generation unit* or the capacity for injection of an *electricity storage unit* within the *IESO control area* that has committed its capacity, or a portion thereof, to an external *control area* and that capacity has been called by the external *control area operator* in accordance with section 20.3 of Chapter 7;

Canadian prime interest rate means the base lending rate that the bank where the *IESO settlement clearing account* is maintained charges for commercial loans to its best and most creditworthy commercial customers;

capability factor means the ratio of the *energy* which could have been delivered by a generating station with *generation unit* limitations in effect, to the *energy*, over the same period of time, that could have been delivered if the generating station had operated at its *maximum continuous rating*;

capacity auction means an auction operated by the *IESO* to acquire *auction capacity*, and includes a *demand response auction;*

capacity auction capacity test means a test which is used to evaluate a *capacity auction resource* on their ability to provide *capacity*, as specified in the applicable *market manual*;

capacity auction clearing price means the price at which *a capacity auction* clears for an *obligation period* and is expressed in $/MW-day;

capacity auction deposit means the deposit required to be made by a *capacity auction participant* in accordance with section 18 of Chapter 7, as a condition of participating in a *capacity auction;*

capacity auction dispatch test means a test conducted by the *IESO* in which *capacity auction resources* are evaluated on their ability to successfully respond to *dispatch* instructions as specified in the applicable *market manual*;

capacity auction eligible generation resource means a *non-committed resource* that is associated with a *generation facility,* which is also a *connected facility* at the commencement of the capacity qualification process for a given *capacity auction*, and which is registered as dispatchable with the *IESO* prior to the *obligation period* in accordance with the timelines specified in the applicable *market manual*;

capacity auction eligible storage resource means a *non-committed resource* associated with an *electricity storage facility*, which is also a *connected facility* at the commencement of the capacity qualification process for a given *capacity auction*, and which is registered as

dispatchable with the *IESO* prior to the *obligation period* in accordance with the timelines specified in the applicable *market manual*;

capacity auction offer means an *offer(s)* from a *capacity auction participant*, in the form of a *price-quantity pair(s)*, to provide *auction capacity* through a *capacity auction resource* for an applicable *obligation period*, reflecting the amount of *auction capacity* that the *capacity auction participant* can reliably and responsibly provide if received as a *capacity obligation*, and which *offer* amount is no greater than the *capacity auction participant's unforced capacity;*

capacity auction participant means a person that is authorized to participate in a *capacity auction* and submit *capacity auction offers*;

capacity auction reference price represents the price at which resources would be incentivized to enter the market and recover the necessary costs to make their capacity available, recognizing their revenue opportunities and avoided costs in the *energy market*. The reference price is directly associated with the *target capacity* as another key reference point in the demand curve;

capacity auction resource means a resource type specified in section 19.1.2 of Chapter 7 and is utilized by a *capacity auction participant* to satisfy a *capacity obligation*;

capacity auction zonal constraints means the minimum or maximum amount of *auction capacity*, or virtual *demand response capacity* that a *capacity auction* seeks to secure for a specific electrical zone or group of electrical zones as detailed by the *IESO* in each pre-auction report;

capacity dispatchable load resource means the *capacity auction resource* associated with a *dispatchable load* that has received a *capacity obligation* in a given *capacity auction* in accordance with the applicable *market manual*;

capacity export agreement means an agreement between the *IESO* and a *control area operator* regarding the management of *called capacity exports*, and which may include but is not limited to *interconnection agreements*;

capacity export request means a request submitted to the *IESO* by a *market participant* for approval to commit the Ontario-based capacity of a *generation unit* or the injection capacity of an *electricity storage unit* to an external *control area* in accordance with section 20.1 of Chapter 7*;*

capacity generation resource means a *capacity auction eligible generation resource* with a *capacity obligation* received in a given *capacity auction* in accordance with the applicable *market manual*;

capacity import call means an *energy* import from an external *control area* that is supported by the capacity of a *generation unit* or the capacity for injection of an *electricity storage unit* within the external *control area* that has committed its capacity, or a portion thereof, to the *IESO control area* and that capacity has been called by the *IESO* in accordance with section 19.9 or 19.9B of Chapter 7;

capacity market participant means a *capacity auction participant* that has registered with the *IESO* as a *capacity market participant,* and who satisfies requirements contemplated in Chapter 7, section 18;

capacity obligation means the amount of *cleared UCAP* that a *capacity market participant* is required to provide from a particular *capacity auction resource* during each hour of the *availability window* of an *obligation period*;

capacity prudential support means the collateral provided by a *market participant* with a *capacity obligation in* accordance with the requirements contemplated in Chapter 2, section 5B;

capacity prudential support obligation means the dollar amount of collateral required as specified by the *IESO* as a condition of satisfying a *capacity obligation*;

capacity qualification request means a request submitted to the *IESO* by a *capacity auction participant* which includes the *installed capacity* and all other applicable information, using the forms specified by the *IESO,* for the determination of the *unforced capacity* of a *capacity auction resource* in the capacity qualification process specified in the applicable *market manual*;

capacity storage resource means a *capacity auction eligible storage resource* with a *capacity obligation* received in a given *capacity auction,* in accordance with the applicable *market manual;*

capacity transferee means a *capacity auction participant* who is willing to accept all or a portion of a *capacity obligation* from a *capacity transferor.* A *capacity transferee* may be the same *capacity auction participant* as the *capacity transferor;*

capacity transferor means a *capacity auction participant* who intends to transfer all or a portion of its *capacity obligation* received through a *capacity auction* to a *capacity transferee.* A *capacity transferor* may be the same *capacity auction participant* as the *capacity transferee;*

Certified black start facility means a *registered facility* that, to the satisfaction of the *IESO* acting reasonably, has complied with and continues to comply with equipment and staffing configurations, training and maintenance programs and inspection and testing regime as set

out in the *market rules* or the *Ontario power system restoration plan*, and from which the *IESO* may direct the delivery of power without assistance from the electrical system.

charge type means the identifier designating an item on an *invoice* or a *settlement statement*;

class r reserve means operating reserve of class r, where r = 1 denotes *ten-minute operating reserve* and r = 2 denotes *thirty minute operating reserve*;

cleared ICAP means, in respect of a *capacity auction resource*, an amount in megawatts of electricity, as determined in accordance with section 18.8.2 of Chapter 7 and adjusted for any applicable *capacity obligation* buy-outs or *capacity obligation* transfers;

cleared UCAP means an amount in megawatts of electricity that a *capacity auction resource* cleared in a given *capacity auction* and adjusted for any applicable *capacity obligation* buy-outs, *capacity obligation* transfers, or in-period *cleared UCAP* adjustments;

close of banking business means 3:00 p.m. on the day the relevant bank is open for business;

cogeneration facility means a *generation facility* that produces both electric *energy* and either steam or other forms of useful energy (such as heat), which are used for industrial, commercial, heating, or cooling purposes, and qualifies for treatment as a Class 43.1 facility or has qualified as a Class 34 facility under the Income Tax Act, R.S.C. 1985, c.1.;

combined guaranteed costs means all eligible costs incurred by a *generation facility* from either the point of ignition or synchronization to the *IESO-controlled grid* as applicable, until the earlier of the end of the *minimum generation block run-time* and the end of the *minimum run-time* for the *generation facility;*

commissioning electricity storage facility means an *electricity storage facility* located within the *IESO control area* that is either (i) newly constructed or (ii) significantly redesigned or rebuilt and is designated by the *IESO* as a *commissioning electricity storage facility* and, in either case, that has not yet completed the commissioning tests referred to in section 2.2D.4.2 of Chapter 7;

commissioning generation facility means a *generation facility* located within the *IESO control area* that is either (i) newly constructed or (ii) significantly redesigned or rebuilt and is designated by the *IESO* as a *commissioning generation facility* and, in either case, that has not yet completed the commissioning tests referred to in section 2.2A.4.2 of Chapter 7;

commitment period means the period of time for each *capacity auction* over which it secures *capacity*. It consists of two *obligation periods;*

confidential information means (i) information which has been supplied by the disclosing person in confidence implicitly or explicitly, where disclosure could reasonably be expected

to: (a) prejudice significantly the competitive position of the disclosing person; (b) interfere significantly with the contractual or other negotiations of the disclosing person or another person; (c) result in undue loss or gain to the disclosing person or another person; (d) compromise the efficiency of the *IESO-administered markets*; (e) result in the disclosing person being in breach of a bona fide confidentiality agreement to which the information is subject; or (f) in the opinion of the *IESO*, pose a potential security threat to the *integrated power system*, the *IESO-administered markets*, or those of neighbouring jurisdictions; and (ii) information that, pursuant to the *market rules* or *applicable law*, the *IESO* or a *market participant* cannot disclose or make available to one or more persons;

confidentiality classification means a classification referred to in section 5.4.1 of Chapter 3;

connect means to form a physical link to or with the *IESO-controlled grid* through a *connection facility*;

connected facility means a *facility* connected to the *IESO-controlled grid*;

connected wholesale customer means a wholesale customer, other than a *distributor*, that is directly connected to the *IESO-controlled grid*;

connection agreement means an agreement entered into between a *transmitter* and a *market participant* governing the terms and conditions pursuant to which the *market participant* is *connected* to the *transmitter's transmission system*;

connection applicant means any of:
(i) a *market participant* or person that applies to the *IESO* for approval of a new *connection* to the *IESO-controlled grid* or for approval of the modification of an existing *connection* to the *IESO-controlled grid*, or
(ii) a *distributor* in whose *distribution system* a *market participant* or person is or intends to be connected as an *embedded generator* or *embedded electricity storage participant* whose *facility* is or will be rated greater than 10 MW, that seeks to establish a new or modify an existing connection pursuant to section 6.1.6 of Chapter 4;

connection assessment means a study conducted by the *IESO* pursuant to section 6.1.5 of Chapter 4 to assess the impact of a new *connection* to the *IESO-controlled grid* or of the modification of an existing *connection* to the *IESO-controlled grid* on the *reliability* of the *integrated power system*;

connection charge means a charge for recovering costs associated with connection to a *transmission system*;

connection facility means a *facility* and equipment that allow a person to become *connected* to the *IESO-controlled grid* and includes, in the case of a *distributor*, distribution assets

owned by a person other than the *distributor* that have been deemed by the *OEB* to be transmission assets;

connection-related reliability information means any information provided or requested pursuant to section 2.2.5 of Chapter 7 and/or section 6.1.6.2 of Chapter 4.

connection point means a point of connection between the *IESO-controlled grid* and a *generation facility, electricity storage facility,* or *load facility*, or the point at which a neighbouring *transmission system* is connected to the *IESO-controlled grid*;

connection request means a request submitted by a *market participant* or a *connection applicant* to a *transmitter* for *connection* to the *IESO-controlled grid*;

connection station service is *station service* associated with transformers, capacitors, switchgear, protection systems and control systems that *connect generation facilities*, *electricity storage facilities, load facilities* or *distribution facilities* to the *IESO-controlled grid*;

conservative operating state means the state described in section 2.5 of Chapter 5;

constrained IESO-controlled grid model means the model capable of being used by the *dispatch algorithm* and described in section 4.5.1.2 of Chapter 7;

constrained off dispatchable load means a *dispatchable load, electricity storage unit* or *boundary entity dispatched* by the *IESO* to consume (or to withdraw in the case of an *electricity storage unit* or *boundary entity*) less *energy* in order to assist in addressing a transmission flow constraint on the *IESO-controlled grid* or a *security limit* in circumstances where such *dispatchable load, electricity storage unit* or *boundary entity* would, but for such constraint or *security limit*, otherwise be or have been *dispatched* to consume (or to withdraw in the case of an *electricity storage unit* or *boundary entity*) more *energy*;

constrained off event means, in respect of a *generation unit,* an *electricity storage unit,* a *dispatchable load*, or a *boundary entity*, the event of being *dispatched* as a *constrained off facility*;

constrained off facility means a *constrained off generation unit,* a *constrained off dispatchable load* or both;

constrained off generation unit means a *generation unit, electricity storage unit,* or *boundary entity dispatched* by the *IESO* to supply (or to inject in the case of an *electricity storage unit* or *boundary entity*) less *energy* in order to assist in addressing a transmission flow constraint on the *IESO-controlled grid* or a *security limit* in circumstances where such *generation unit, electricity storage unit,* or *boundary entity* would, but for such constraint or *security limit,*

otherwise be or have been *dispatched* to supply (or to inject in the case of an *electricity storage unit* or *boundary entity*) more *energy*;

constrained on dispatchable load means a *dispatchable load, electricity storage unit* or *boundary entity dispatched* by the *IESO* to consume (or to withdraw in the case of an *electricity storage unit* or *boundary entity*) more *energy* in order to assist in addressing a transmission flow constraint on the *IESO-controlled grid* or a *security limit* in circumstances where such *dispatchable load, electricity storage unit* or *boundary entity* would, but for such constraint or *security limit*, otherwise be or have been *dispatched* to consume (or to withdraw in the case of an *electricity storage unit* or *boundary entity*) less *energy*;

constrained on event means, in respect of a *generation unit,* an *electricity storage unit,* a *dispatchable load* or a *boundary entity*, the event of being *dispatched* as a *constrained on facility*;

constrained on facility means a *constrained on generation unit,* a *constrained on dispatchable load* or both;

constrained on generation unit means a *generation unit, electricity storage unit,* or *boundary entity dispatched* by the *IESO* to supply (or to inject in the case of an *electricity storage unit* or a *boundary entity*) more *energy* in order to assist in addressing a transmission flow constraint on the *IESO-controlled grid* or a *security limit* in circumstances where such *generation unit, electricity storage unit,* or *boundary entity* would, but for such constraint or *security limit*, otherwise be or have been *dispatched* to supply (or to inject in the case of an *electricity storage unit, boundary entity*) less *energy*;

consumer means a person who uses, for the person's own consumption, electricity that the person did not generate;

contingency event means the unexpected failure of a single component or multiple components connected to the *electricity system*;

contracted ancillary services means *ancillary services*, other than *operating reserve,* procured by the *IESO* by contract rather than in the *real-time markets* in accordance with sections 9.2 to 9.5 of Chapter 7;

contributor outage means an *outage* of a *demand response contributor* where its energy consumption is less than 1% of its peak consumption measured in the prior three months, excluding any *outages* related to *generation units*;

control area means an area on an electricity system where supply and demand are kept in balance through *dispatch* by the *control area operator*;

control area operator means the person responsible for the *secure* operation of a *control area*, and includes independent system operators and regional transmission organizations in other jurisdictions;

control centre means, in respect of a *registered facility* or group of *facilities,* an *attended location* where signals and instructions for controlling the *facilities* are received from an *authority centre* or the *IESO*, and transferred directly to the *facilities* for implementation;

costs of the arbitration means the fees and expenses of an *arbitrator* and any other costs and expenses related to the arbitration of a dispute under section 2 of Chapter 3, other than the legal costs and expenses of the parties to the dispute and of any intervener;

costs of the mediation means the fees and expenses of a *mediator* and any other costs and expenses related to the mediation of a dispute under section 2 of Chapter 3, other than the legal costs and expenses of the parties to the dispute and of any person permitted by the *mediator* to attend a mediation session pursuant to section 2.6.6;

current period adjustment means an adjustment that is effected against amounts owing or payable in respect of transactions reflected in a *settlement statement* issued for the *billing period* or *trading day* during which the *current period adjustment* is effected regardless of the *billing period* or *trading day* during which the *preliminary settlement statement* to which the adjustment relates occurred;

curtailment means the involuntary curtailment of *non-dispatchable load* as a result of insufficient *generation capacity* or *electricity storage capacity*, of a limitation in the capacity of a *transmission system* or of actions taken by the *IESO* pursuant to Chapter 5 to maintain the *reliability* of the *IESO-controlled grid* or of the *electricity system*;

daily cascading hydroelectric dependency means there is a minimum hydraulic time lag of less than 24 hours from a hydroelectric *generation facility* to one or more adjacent upstream and/or downstream hydroelectric *generation facilities* operated by the same *registered market participant*;

data collection system means a means of extracting *metering data* from a *metering installation* and transferring such *metering data* into a remote *metering database*;

data logger means a device designed to be capable of reading and holding data until that data is collected;

default amount means a dollar amount by which a *market participant* has defaulted upon its obligations to *settle* with the *IESO* and shall, for purposes of the imposition of a *default levy,* be calculated in accordance with section 8.3.1 or 8.5.1 of Chapter 2;

default interest means interest at the *default interest rate*;

default interest rate means the interest rate calculated as the *Canadian prime interest rate* plus 2%;

default levy means a levy imposed by the *IESO* on *non-defaulting market participants* in accordance with section 8 of Chapter 2;

defaulting market participant means a *market participant* that is in default of payment in respect of monies owing to the *IESO* under the *market rules*;

default protection amount means, in respect of a given *market participant*, the dollar amount determined from time to time by the *IESO* for that *market participant* in accordance with section 5.3.8 of Chapter 2;

defined meter point means (a) in respect of a *facility connected* to the *IESO-controlled grid* by a *connection facility* that is a radial line designated by the *IESO* for such purpose, the point at a voltage above 50 kV at which the designated radial line is *connected* to (i) the high voltage bus of the *facility*, or (ii) the *facility*, if there is no such high voltage bus; (b) in respect of a *facility connected* to the *IESO-controlled grid* by a *connection facility* other than one referred to in (a), the point at a voltage above 50 kV at which the *connection facility* is *connected* to the *IESO-controlled grid*; and (c) in respect of an *embedded market participant*, the point at which the *embedded market participant's facility* is connected to the distribution system within which it is *embedded*;

delivery point means a uniquely identified reference point determined in accordance with section 2.4A.1 of Chapter 9 and used for *settlement* purposes in the *real-time markets*, other than in respect of transactions involving the transmission of *energy* or *ancillary services* into or out of the *IESO-controlled grid* from a neighbouring *transmission system*;

demand means the rate at which electric *energy* is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time;

demand response auction means an auction operated by the *IESO* prior to December 31, 2019, to acquire *demand response capacity,* in accordance with section 18 of Chapter 7;

demand response bid price threshold means the price at which a *demand response energy bid* shall exceed, in the day-ahead commitment process and the *real-time energy market,* to be considered a *demand response energy bid* in accordance with the applicable *market manual*;

demand response capacity means the quantity of load reduction provided by *dispatchable loads* and/or *hourly demand response resources*;

demand response contributor means a *load facility* that is associated with an *hourly demand response resource* and is used to satisfy in whole or a portion of a *capacity obligation.*

Demand response contributors are registered by *capacity market participants* as part of the contributor management process detailed in the applicable *market manual*;

demand response energy bid means a *bid* in the day-ahead commitment process and the *real-time energy market,* greater than the *demand response bid price threshold*, except during the *capacity auction capacity test* testing window, and less than the *MMCP,* by a *capacity market participant* entered for either a *capacity dispatchable load resource* or an *hourly demand response resource* to fulfill a *capacity obligation* availability requirement;

demand response resource means, in a *capacity auction,* either an *hourly demand response resource* or a *capacity dispatchable load resource*;

designated constrained off watch zone means an area within Ontario as set out in the applicable *market manual*, including connected *intertie zones*, that is monitored to determine if persistent and significant congestion management *settlement* credit payments for *constrained off events* are being made. These watch zones may be further designated for injections, withdrawals or both;

disaster recovery plan means the plan for maintaining *IESO* settlement functions in the event of a disaster;

disconnect means to separate *facilities* or equipment from the *IESO-controlled grid*, a *transmission system,* a *distribution system* or from a host *market participant*, as the case may be, and, in the case of a *distributor* that is *connected* to the *IESO-controlled grid* by distribution assets owned by a person other than the *distributor* that have been deemed by the *OEB* to be transmission assets, to separate the *distributor* from those assets;

disconnection order means an order issued by the *IESO* to any one of, or a combination of, a *transmitter,* a *distributor* or other *market participant*, directing such *transmitter, distributor* or other *market participant*, as applicable, to *disconnect facilities* or equipment specified within such order;

dispatch means the process by which the *IESO* directs the real-time operation of *registered facilities* to cause a specified amount of electric *energy* or *ancillary service* to be provided to or taken off the *electricity system*;

dispatch algorithm means the mathematical algorithm used by the *IESO* to determine various operating schedules and prices in accordance with Chapter 7;

dispatch centre means, in respect of a *registered facility* or group of *facilities,* an *attended location* at which employees have the authority and capability to *dispatch* the *facilities* based on the *dispatch instructions* received from the *IESO;*

dispatch data means the *offers*, *bids*, *self-schedules* and estimates of *intermittent generation* required to be submitted to the *IESO* in accordance with Chapter 7 and used by the *IESO* to determine physical operations and *physical market prices;*

dispatch day means a period from midnight EST to the following midnight EST;

dispatch hour means a one hour period within a *dispatch day*;

dispatch instructions means in respect of a *registered facility* other than a *boundary entity*, a physical operating instruction issued by the *IESO* either in the *real-time dispatch process* or in those *dispatch intervals* when *administrative prices* were applied pursuant to section 8.4A of Chapter 7 or the *IESO-administered markets* are suspended pursuant to section 13 of Chapter 7, and, in respect of a *registered facility* that is a *boundary entity*, the *interchange schedule* pertaining to that *registered facility*;

dispatch interval means a five-minute interval within a *dispatch hour*;

dispatch period means, in respect of a *pre-dispatch schedule*, a *dispatch hour* and, in respect of a *real-time schedule*, a *dispatch interval*;

dispatch scheduling error means an error made by the *IESO* in the *real-time dispatch process,* in circumstances where these *market rules, market manuals* or any standard, policy or procedure established by the *IESO* pursuant to these *market rules* do not admit of any deviation or departure from such *real-time dispatch process*;

dispatch workstation means the communication equipment that is required to be installed and maintained in accordance with Appendix 2.2 for the purposes referred to in section 1.3.1 of Appendix 2.2 of Chapter 2;

dispatchable load means a *load facility* which is subject to *dispatch* by the *IESO* and whose level is selected or set based on the price of *energy* in the *real-time market,* and excludes *hourly demand response resources*;

dispute outcome means the outcome of a dispute resolution process that requires adjustments to one or more *settlement statements*, whether arising from good faith negotiations, mediations, or an *arbitrator*'s order;

dispute resolution panel means the panel of the same name established by the *IESO* pursuant to the *Governance and Structure By-law*;

distribute, with respect to electricity, means to convey electricity at voltages of 50 kilovolts or less;

distribution system means a system for *distributing* electricity, and includes any structures, equipment or other things used for that purpose;

distributor means a person who owns or operates a *distribution system*;

elapsed time to dispatch is the minimum amount of time, in minutes, between the time at which a startup sequence is initiated for a *generation unit* and the time at which it becomes dispatchable by reaching its *minimum loading point*;

Electricity Act, 1998 means the *Electricity Act*, *1998*, S.O. 1998, c. 15, Schedule A;

Electricity and Gas Inspection Act means the Electricity and Gas Inspection Act, R.S.C. 1985, c. E-4;

electricity storage capacity means the maximum power that an *electricity storage unit* or *electricity storage facility* can supply, usually expressed in megawatts (MWs);

electricity storage energy rating means the maximum amount of stored energy of an *electricity storage unit* or *electricity storage facility*, usually expressed in megawatt hours (MWhs);

elec*tricity storage facility* means a *facility* that is comprised of one or more *electricity storage units* and includes any structures, equipment or other things to support the functioning of its *electricity storage units;*

electricity storage facility size means the greater of the absolute values of the maximum injection and maximum withdrawal capabilities of the *electricity storage facility* expressed in either megawatts (MWs) or megavolt amperes (MVAs);

electricity storage participant means a person who owns or operates an *electricity storage facility*;

electricity storage station service means *station service* associated with an *electricity storage facility* comprising one or more *electricity storage units* each of which is a *registered facility* or which together have been aggregated as a *registered facility* in accordance with section 2.3 of Chapter 7;

electricity storage unit means the equipment used for the sole purpose of withdrawing electricity from the *electricity system*, storing that electricity, and re-injecting it, or a portion thereof, into the *electricity system*;

electricity storage unit size means the greater of the absolute values of the maximum injection and maximum withdrawal capabilities of the *electricity storage unit* expressed in either megawatts (MWs) or megavolt amperes (MVAs);

electricity system means the *integrated power system* and all *registered facilities* connected to that system;

electronic funds transfer means the transfer of funds between bank accounts by electronic means;

electronic information system means the internet or the real-time communication network that is used for the exchange of information referred to in section 1.4.1 of Appendix 2.2 of Chapter 2 via the *participation workstation*;

embedded connection point means the point of connection between a *facility* and a *distribution system*;

embedded generator means a *generator* within the *IESO control area* whose *generation facility* is not directly connected to the *IESO-controlled grid* but is instead connected to a *distribution system* and *embedded generation facility* shall be interpreted accordingly;

embedded electricity storage facility means an *electricity storage facility* within the *IESO control area,* not directly connected to the *IESO-controlled grid* but is instead connected to a *distribution system*;

embedded electricity storage participant means an *electricity storage participant* within the *IESO control area* whose *electricity storage facility* is not directly connected to the *IESO-controlled grid* but is instead connected to a *distribution system;*

embedded load consumer means a person that owns or operates an *embedded load facility*;

embedded load facility means a *dispatchable load* or a *non-dispatchable load* within the *IESO control area* that is not directly *connected* to the *IESO-controlled grid* but is instead embedded within a *distribution system*;

embedded market participant means a *market participant* within the *IESO control area* whose *facility* is not directly connected to the *IESO-controlled grid* but is instead connected to a *distribution system*;

embedded RWM means an *RWM* that is not a *primary RWM* and that measures flows that are also part of the flows measured by a *primary RWM*;

emergency means any abnormal system condition that requires remedial action to prevent or limit loss of a *transmission system* or generation supply that could adversely affect the *reliability* of the *electricity system*;

emergency energy means *energy* acquired by the *IESO* from another *control area* or provided by the *IESO* to another *control area* in order to maintain the *reliability* of the *IESO-controlled grid* or of a *transmission system* within such other *control area*;

emergency operating state means the state described in section 2.3 of Chapter 5;

emergency preparedness plan means a plan prepared by the *IESO* or required to be prepared by a *market participant* and submitted to the *IESO* in accordance with section 11.2.1 of Chapter 5;

energy means, in respect of the *market rules* other than Chapter 5 or 6, real *energy* only and may, in respect of Chapter 5 or 6, mean both real *energy* and reactive *energy* if the context so requires;

energy market means the *real-time market* for *energy* administered by the *IESO* pursuant to Chapter 7 in which *energy offers* and *energy bids* are cleared and a *market price* for *energy* is determined;

enhanced combined cycle facility means a combined cycle facility in which the steam utilized to generate electricity in one or more of the steam turbines is supplemented by recovery of waste heat from an independent industrial process/processes such as waste heat from the gas turbine exhaust of a natural gas compressor station, and qualifies for treatment as a Class 43.1 facility or has qualified as a Class 34 facility under the Income Tax Act, R.S.C. 1985, c.1. Combined cycle facilities are *generation facilities* in which electricity is generated by one or more combustion turbines or engines, and by one or more steam turbines for which steam is supplied by recovery of waste heat from one or more of the combustion turbines or engines;

estimated market prices means the price forecasts developed by the *IESO* for the purposes of determining *market participant maximum net exposures* and *prudential support obligations*;

exemption means an exclusion from one or more specific obligations or standards which are or may be imposed on the *exemption applicant* or in respect of the *exemption applicant's facilities* or equipment pursuant to the *market rules*, *market manuals* or from any standard, policy or procedure established by the *IESO* pursuant to the *market rules*;

exemption applicant means the *IESO* or a person, including a *market participant*, who submits an application to be exempted from an obligation or standard under the *market rules*;

exemption application means the material submitted by the *exemption applicant* pursuant to the practice and procedure established by the *IESO Board* for the processing of an *exemption*;

event of default means an event referred to in section 6.3.1 of Chapter 3;

existing support has the meaning ascribed thereto in section 5.2.5 of Chapter 2;

export transmission service means the *transmission service* relating to the use of the *IESO-controlled grid* for the transmission of *energy* out of the *IESO control area* into a neighbouring *transmission system* and in respect of which charges are required to be collected by the *IESO* pursuant to section 4 of Chapter 10;

facility means a *generation facility*, a *load facility,* an *electricity storage facility,* a *connection facility,* a *transmission system*, or a *distribution system,* located within the *IESO control area*, or any other equipment that is a component or part of the *electricity system*;

federal metering requirements means all requirements relating to *meters* and to *metering installations* imposed by or under the authority of an Act of Parliament;

final recalculated settlement statement means the *recalculated settlement statement* issued by the *IESO* in accordance with either section 6.3.6(b) or section 6.3.17(g) of Chapter 9;

final settlement statement means the *IESO's* final statement of the payments to be made by or to a *market participant* with respect to a given *billing period* and, in respect of the *settlement* of the purchase or sale of *transmission rights* in the *TR market*, the *IESO*'s final statement of the payments to be made by or to a *TR holder* with respect to a given *TR auction* or the final statement of the payments to be made by or to a *TR holder* with respect to a given *billing period*;

financial market participant means a person that participates only in the *TR market*;

flexible nuclear generation means the component of a nuclear *generation facility* that has flexibility for reductions due to the operation of condenser steam discharge valves, and is made available at the sole discretion of the *flexible nuclear generator* to manoeuvre without requiring a unit to shutdown under normal operations, while respecting safety, technical, equipment, environmental and regulatory restrictions;

flexible nuclear generator means a *generator* whose *generation facility* has a component classified as *flexible nuclear generation*;

forbidden region means a predefined operating range within which a hydroelectric *generation facility* cannot maintain steady operation without causing equipment damage. A hydroelectric *generation facility* may have more than one *forbidden region*;

force majeure event means, in relation to a person, any event or circumstance, or combination of events or circumstances, (i) that is beyond the reasonable control of the person; (ii) that adversely affects the performance by the person of its obligations under these *market rules*; and (iii) the adverse effects of which could not have been foreseen and prevented, overcome, remedied or mitigated in whole or in part by the person through the

exercise of diligence and reasonable care, and includes, but is not limited to, acts of war (whether declared or undeclared), invasion, armed conflict or act of a foreign enemy, blockade, embargo, revolution, riot, insurrection, civil disobedience or disturbances, vandalism or act of terrorism; strikes, lockouts, restrictive work practices or other labour disturbances; unlawful arrests or restraints by governments or governmental, administrative or regulatory agencies or authorities; orders, regulations or restrictions imposed by governments or governmental, administrative or regulatory agencies or authorities unless the result of a violation by the person of a permit, licence or other authorization or of any *applicable law*; and acts of God including lightning, earthquake, fire, flood, landslide, unusually heavy or prolonged rain or accumulation of snow or ice or lack of water arising from weather or environmental problems; provided however, for greater certainty, that (i) the lack, insufficiency or non-availability of funds shall not constitute a *force majeure event*, (ii) an act of the *IESO* effected in accordance with the *market rules* or with the provisions of any form, policy, guideline or other document referred to in section 7.7 of Chapter 1 shall not constitute a *force majeure event* in respect of a *market participant*, and (iii) an act of a *market participant* effected in accordance with the *market rules* or with the provisions of any form, policy, guideline or other document referred to in section 7.7 of Chapter 1 shall not constitute a *force majeure event* in respect of the *IESO*;

forced outage means an unanticipated intentional or automatic removal from service of equipment or the temporary de-rating of, restriction of use or reduction in performance of equipment;

forecasting entity means the entity or entities contracted by the *IESO* to provide forecasting services relating to *variable generation*;

forward period means the period of time beginning three (3) *business days* following a *capacity auction*, to the commencement of an *obligation period*;

funds transfer process means the process by which funds are transferred between the respective bank accounts of the *IESO*, *market participants* and *transmitters*;

generation capacity means the maximum power that a *generation unit*, generation station or other electrical apparatus can supply, usually expressed in megawatts;

generation facility means a *facility* for generating electricity or providing *ancillary services*, other than *ancillary services* provided by a *transmitter* or *distributor* through the operation of a *transmission* or *distribution system*, and includes any structures, equipment or other things used for that purpose;

generation station service means *station service* associated with a *generating facility* comprising one or more *generation units* each of which is a *registered facility* or which together have been aggregated as a *registered facility* in accordance with section 2.3 of Chapter 7;

generation unit means the equipment that actually *generates* electricity, together with all related equipment essential to its functioning as a single entity;

generator means a person who owns or operates a *generation facility*;

generator-backed capacity auction eligible import resource means one or more *generator-backed import contributors.* No portion of the capacity that is being offered into the *IESO capacity auction* may be *over committed capacity;*

generator-backed capacity import resource means a *generator-backed capacity auction eligible import resource* with a *capacity obligation* received in a given *capacity auction* in accordance with the applicable *market manual;*

generator-backed import contributor means an existing in-service *generation facility* or *storage facility* associated with a *generator-backed capacity auction eligible import resource*, and which is located in a neighbouring *control area* that has an agreement with the *IESO* to allow for the trade of capacity, is able to qualify capacity in accordance with the applicable *market manual*, has been in operation for at least one year prior to the *capacity auction*, is a resource type that is currently enabled to participate in the *IESO's capacity auction*, and is able to transmit energy from the *generation facility* or the *storage facility* to the Ontario border;

good utility practice means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry in North America during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgement in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, *reliability*, safety and expedition. *Good utility practice* is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in North America;

Governance and Structure By-law means the by-law of the *IESO* made pursuant to subsection 22(2) of the *Electricity Act, 1998*;

gross MW as related to active power output from an *electricity storage unit*, *generation unit*, or *facility*, is the total amount of active power produced by such unit or *facility* as measured at the unit's terminal or as measured as a sum of active power produced by the *facility*'s individual units;

gross MX as related to reactive power output from an *electricity storage unit*, *generation unit*, or *facility*, is the total amount of reactive power produced by such unit or *facility* as measured at the unit's terminal or as measured as a sum of reactive power produced by the *facility*'s individual units;

high priority path facility means a voice communication facility that meets the requirements of section 1.1.7 of Appendix 2.2 of Chapter 2;

high-risk operating state means the state described in section 2.4 of Chapter 5;

historical reference price means (i) in respect of an *investigated facility* which is not a hydroelectric *generation facility*, the unweighted average of the price contained in all *energy offers* or *energy bids* submitted by the *registered market participant* for that *investigated facility* and accepted by the *IESO*, as reflected in the most recent *market schedules* for that *investigated facility* for the *dispatch intervals* to which such *energy offers* or *energy bids* relate, during all relevant hours in the ninety days preceding the date for which an *investigated price* is submitted by the *registered market participant* for that *investigated facility* and (ii) in respect of an *investigated facility* which is a hydroelectric *generation facility*, the average *market price* weighted by the *market schedule* quantity during all relevant intervals in the thirty days preceding the date on which an *investigated price* was submitted by the *registered market participant* for that *investigated facility*;

hourly demand response resource means the *capacity auction resource* type that is a registered facility that has received a *capacity obligation* in a given *capacity auction* and is used by a *capacity market participant* to satisfy a *capacity obligation* on an hourly basis and is activated by the *IESO* in accordance with section 19.4 of Chapter 7*;*

hourly markets means those markets in which quantities and prices are determined using five-minute quantity and price information to derive composite hourly quantities and prices;

hourly Ontario energy price or HOEP means the arithmetic average of the uniform Ontario *energy* prices determined for each *dispatch interval* pursuant to section 8.3 of Chapter 7;

hourly uplift means the uplift payments that are determined for each hour based on *real-time market* results in that hour;

IESO or the *Independent Electricity System Operator* means the Independent Electricity System Operator, which is the continuation of the Independent Electricity Market Operator established under Part II of the *Electricity Act, 1998*;

IESO adjustment account means the *settlement account* operated by the *IESO* which is used for adjustments in *settlement* payments after a preliminary market *settlement* has been made;

IESO-administered markets means the markets established by the *market rules*;

IESO administration charge means the charge imposed by the *IESO* on *market participants* for the purpose of recovery by the *IESO* of its administration costs;

IESO Board means the Board of Directors of the *IESO*;

IESO catalogue of reliability-related information means the catalogue described in section 14.1.3 of Chapter 5;

IESO control area means that area, including the *IESO-controlled grid*, with respect to which the *IESO* is the *control area operator*;

IESO-controlled grid means the *transmission systems* with respect to which, pursuant to *operating agreements*, the *IESO* has authority to direct operations;

IESO payment date means the date on which the *IESO* is to make *settlement* payments to *market participants*;

IESO prepayment account means the *settlement account* operated by the *IESO* to hold payments by *market participants* prior to the relevant *market participant payment date* to which such payments relate;

IESO settlement clearing account means the *settlement account* operated by the *IESO* for holding market settlement payments made to the *IESO*;

IESO Settlement Schedule & Payments Calendar or SSPC means the *IESO*'s calendar of dates for providing settlement information to *market participants* and of dates on which settlement payments must be made by and to the *IESO*;

information confidentiality catalogue means the applicable *market manual* listing information and its *confidentiality classification* determined pursuant to section 5 of Chapter 3;

installed capacity or *ICAP* means the amount, in MW, of electricity submitted by a *capacity auction participant,* in accordance with the applicable *market manual*, during the *IESO's* capacity qualification process that reflects a *capacity auction resource's* maximum seasonal generation capability, load reduction capability, or import capability;

instrument transformer means an iron cored device that isolates a *meter* from the primary voltage while passing a correct value of the primary measured quantity to the *meter*;

integrated power system means the *IESO-controlled grid* and the structures, equipment and other things that connect the *IESO-controlled grid* with *transmission systems* and *distribution systems* in Ontario and *transmission systems* outside Ontario;

interchange schedule data means data pertaining to *interchange schedules*;

interchange schedule means the scheduled *intertie* flow between the *IESO-controlled grid* and a neighbouring *control area*;

interconnected systems means two or more individual *transmission systems* that have one or more *interties*;

interconnected transmitter means a *transmitter* whose transmission facilities are outside the Ontario *control area* and has entered into an *interconnection agreement* with the *IESO;*

interconnection agreement means an agreement between the *IESO* and another *control area operator, security coordinator* or *interconnected transmitter* regarding the operation of an *interconnection* with the *IESO-controlled grid*;

interconnection means a connection between the *IESO-controlled grid* and a *transmission system* outside the *IESO control area* that have one or more interconnecting *interties*;

intermittent generator means a *generation facility* located within the *IESO control area* that generates on an intermittent basis as a result of factors beyond the control of the *generator* unless limited by *dispatch,* and excludes a *variable generator*;

intertie means a transmission line which forms part of an *interconnection*;

intertie congestion price (ICP) means, in respect of a given *dispatch hour*, a price equal to the projected *market price* for *energy or operating reserve* for a given *intertie zone* minus the projected uniform *market price* for *energy* or *operating reserve* respectively*,* in the *IESO control area,* determined in accordance with section 8.1.1A of Chapter 7;

intertie metering point means a point within an *intertie zone*, at which the *IESO* obtains *interchange schedule data* for the purposes of the *settlement process*;

intertie zone means a market region designated by the *IESO* which is connected to the *IESO-controlled grid* by an *intertie*;

investigated facility means, in respect of an *investigated price,* the *constrained on facility* or the *constrained off facility* whose *registered market participant* submitted the *energy offer* or *energy bid* that contains that *investigated price*;

investigated price means a price contained in an *energy offer* or an *energy bid* submitted by the *registered market participant* for a *constrained on facility* or a *constrained off facility* that is the subject of investigation or of an inquiry pursuant to Appendix 7.6 of Chapter 7 in respect of a given *constrained on event* or a given *constrained off event*;

invoice means an invoice from the *IESO* to a *market participant* which sets forth a *settlement amount*;

licence means a licence issued by the Ontario Energy Board pursuant to the *Ontario Energy Board Act, 1998*;

line connection service means the *transmission service* relating to the use of the line connection assets of a *transmitter* whose *transmission system* forms part of the *IESO-controlled grid* and in respect of which charges are required to be collected by the *IESO* pursuant to section 5.1.1 of Chapter 10;

load facility means a *facility* that draws electrical *energy* from the *integrated power system*;

load serving breaker means a device, or sequence of devices, which provide a single path for *energy* to flow between a *connection facility* and a *load facility*;

local area has the meaning ascribed thereto in section 5.4.1 of Chapter 5;

long-term auction means a *TR auction* conducted by the *IESO* for the purchase and sale of *long-term transmission rights* and that may also include the purchase and sale of *short-term transmission rights*;

long-term transmission right means a *transmission right* that is valid for a period of one year;

lower energy limit means the lowest energy amount to which an *electricity storage unit* can be consistently discharged without damage beyond expected degradation from normal use;

main/alternate metering installation means a *metering installation* comprised of two *revenue meters* measuring the same electrical quantities;

major dispatchable load facility means a *dispatchable load facility* that includes a *dispatchable load* that is rated at 100 MVA or higher; that comprises *dispatchable loads* the ratings of which in the aggregate equals or exceeds 100 MVA; or that is re-classified as a *major dispatchable load facility* pursuant to section 1.5.1 of Appendix 2.2 of Chapter 2 or section 7.8.1 of Chapter 4;

major electricity storage facility means an *electricity storage facility* that includes an *electricity storage unit* with an *electricity storage unit size* rated at 100 MVA or higher; or that comprises multiple *electricity storage units*, the aggregated *electricity storage unit size* ratings of which equals or exceeds 100 MVA; or that is re-classified as a *major electricity storage facility* pursuant to section 1.5.1A of Appendix 2.2 of Chapter 2 or section 7.8.2A of Chapter 4;

major generation facility means a *generation facility* that provides *regulation*; that includes a *generation unit* that is rated at 100 MVA or higher; that comprises *generation units* the ratings of which in the aggregate equals or exceeds 100 MVA; or that is re-classified as a *major generation facility* pursuant to section 1.5.1 of Appendix 2.2 of Chapter 2 or section 7.8.1 of Chapter 4;

margin call means a notice given by the *IESO* to a *market participant* pursuant to section 5.4.2 of Chapter 2 when the *actual exposure* of that *market participant* equals or exceeds its *trading limit*;

market assessment unit means the entity established by the *IESO* pursuant to section 3.2.1 of Chapter 3;

market commencement date means the date on which the *real-time market* commences operation;

market creditor means a person, including a *market participant*, that is owed monies by the *IESO* as a result of sales made or contracts existing in the *IESO-administered markets*;

market debtor means a person, including a *market participant*, that owes monies to the *IESO* as a result of purchases made or contracts existing in the *IESO-administered markets*;

market manual means a *published* document that is entitled as such and that describes procedures, standards and other requirements to be followed, met or performed by *market participants,* the *IESO* and other persons in fulfilling their respective obligations under the *market rules*;

market monitoring unit means the entity that monitors the markets administered by a *control area operator* or *security coordinator;*

market participant means a person who is authorized by the *market rules* to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid* and includes a person that has received conditional authorization under section 4 of Chapter 2;

market participant payment date means the date on which *market participants* are to make settlement payments to the *IESO*;

market participant settlement account means an account designated by the particular *market participant* as the account from and into which *settlement* payments are made;

market price means the price of *energy* or *operating reserve* determined in the *real-time market* or the price of *auction capacity* determined in the *capacity auction* in accordance with the provisions of Chapter 7;

market rules means rules made under section 32 of the *Electricity Act, 1998*;

market schedule means the *dispatch* schedule which would have resulted in the absence of transmission constraints on the *IESO-controlled grid*;

market surveillance panel means the panel of the same name continued as a panel of the *OEB* in accordance with subsection 4.3.1(1) of the *Ontario Energy Board Act, 1998*;

maximum continuous rating means the gross or net maximum electrical output (in megawatts) which a *generation unit* or generating station is currently capable of producing continuously. This may include seasonal effects or other "long-term" deratings;

maximum market clearing price or *MMCP* means the maximum price that a *market participant* may be charged or paid for *energy*;

maximum number of starts per day is the number of times that a unit can be started within a *dispatch day*;

maximum net exposure means, in respect of a given *market participant*, the amount calculated from time to time by the *IESO* for that *market participant* in accordance with section 5.3 of Chapter 2;

maximum operating reserve price or *MORP* means the maximum price that can be determined or paid to a *market participant* for *operating reserve*;

maximum regulation price or *MRP* means the maximum price that a *market participant* may be charged or paid for *regulation*;

mediator means a qualified person appointed pursuant to section 2.6 of Chapter 3 to mediate a dispute;

meter means a device that measures and records active *energy*, reactive *energy* or both and shall be deemed to include the *data logger* but to exclude the *instrument transformers*;

meter point means, in respect of a *load facility* and of a *generation facility* or *electricity storage facility* that is injecting, with respect to which the current transformers are located on the output side of the *generation facility* or *electricity storage facility*, the physical location of the current transformers used to measure power flow and, in respect of a *generation facility* or an *electricity storage facility* with respect to which the current transformers are located on the grounded side of the *generation facility*, or the *electricity storage facility* the physical location of the voltage transformers;

metered market participant means, in respect of a *facility*, the *market participant* designated as the *metered market participant* for that *registered facility* in accordance with Chapter 9;

metering data means electrical quantities measured and recorded by a *metering installation*;

metering database means an information system established and maintained by the *IESO* in accordance with Chapter 6 for the purpose of storing *metering data*;

metering installation means any apparatus, including but not limited to an *RWM*, used to measure electrical quantities and includes the communication system by which *metering data* is transferred to the relevant telecommunications network through which *metering data* is transferred to the communication interface of the *metering database*;

metering interval means the five-minute period over which *metering data* is collected;

metering registry means the information system established and maintained by the *IESO* in accordance with Chapter 6;

metering service provider means a person that provides, installs, commissions, registers, maintains, repairs, replaces, inspects and tests *metering installations*;

minimum generation block down time is the minimum time, in hours, between the time a *generation facility* was last at its *minimum loading point* before de-synchronization and the time the *generation facility* reaches its *minimum loading point* again after synchronization;

minimum generation block run-time means the number of hours, specified by the *market participant*, that a *generation facility* must be operating at *minimum loading point*; in accordance with the technical requirements of the *facility*;

minimum loading point means the minimum output of *energy* specified by the *market participant* that can be produced by a *generation facility* under stable conditions without ignition support;

minimum run-time means the number of hours required for the *generation facility* to ramp from a cold start to *minimum loading point* plus *minimum generation block run-time,* specified by the *market participant*, in accordance with the technical requirements of the *facility*;

minimum shut-down time means the minimum time in hours between shutdown and start-up of a *generation unit*. This is measured from the time of de-synchronization from the *IESO-controlled grid* to the time of re-synchronization on start-up;

minimum trading limit means, in respect of a given *market participant*, the dollar amount determined from time to time by the *IESO* for that *market participant* in accordance with section 5.3.4 of Chapter 2;

Minister means the Minister of Energy, Northern Development and Mines or such member of the Executive Council that may be assigned the administration of the *Electricity Act, 1998* under the *Executive Council Act, 1990*;

minor amendment, in respect of the *market rules*, means an *amendment* to the *market rules* to correct a typographical or grammatical error, or to effect a change of a non-material procedural nature;

minor dispatchable load facility means a *dispatchable load facility* that includes a *dispatchable load* that is rated at 1 MVA or higher but less than 20 MVA; that comprises *dispatchable loads* the ratings of which in the aggregate equals or exceeds 1 MVA but is less than 20 MVA; or that is re-classified as a *minor dispatchable load facility* pursuant to section 1.5.2 of Appendix 2.2 of Chapter 2 or section 7.8.2 of Chapter 4;

minor electricity storage facility means an *electricity storage facility* that includes an *electricity storage unit* with an *electricity storage unit size* rated at 1 MVA or higher but less than 20 MVA; or that comprises multiple *electricity storage units*, the aggregated *electricity storage unit size* ratings of which equals or exceeds 1 MVA but is less than 20 MVA; or that is re-classified as a *minor electricity storage facility* pursuant to section 1.5.1A or 1.5.2A of Appendix 2.2 of Chapter 2 or section 7.8.2A or 7.8.2B of Chapter 4;

minor generation facility means a *generation facility* that includes a *generation unit* that is rated at 1 MVA or higher but less than 20 MVA; that comprises *generation units* the ratings of which in the aggregate equals or exceeds 1 MVA but is less than 20 MVA; or that is re-classified as a *minor generation facility* pursuant to section 1.5.1 or 1.5.2 of Appendix 2.2 of Chapter 2 or section 7.8.1 or 7.8.2 of Chapter 4;

monthly confirmation notice means the notice provided by the *IESO* to each *market participant* containing a summary of the *market participant's settlement* payments made during a calendar month and of the payments outstanding for that calendar month;

neighbouring electricity system means a system comprising generation, transmission and *load facilities* that is connected to the *electricity system* via one or more *interconnections*;

NERC means the North American Electric Reliability Corporation;

NERC confidentiality agreement means an agreement required to be executed between NERC and all *security coordinators* and, where applicable, *control area operators* and *interconnected transmitters* which ensures that required data is available and that the confidentiality of such data is protected and disclosed only to those responsible for maintaining the operational security of electricity supply in North America;

net MW as related to active power output from an *electricity storage unit*, *generation unit*, or *facility* is equal to the applicable unit or *facility*'s *gross MW* output less the applicable unit or *facility station service* MW load and MW losses to the *defined meter point* for that applicable unit or *facility*;

net MX as related to reactive power output from an *electricity storage unit*, *generation unit*, or *facility* is equal to the applicable unit or *facility*'s *gross MX* output less the applicable unit or *facility station service* MX load and MX losses to the *defined meter point* for that applicable unit or *facility;*

net transaction dollar amount means an amount calculated in accordance with section 8.6.1.1 of Chapter 2;

network service means the *transmission service* relating to the use of the *IESO-controlled grid* for the transmission of *energy* and *ancillary services*, other than in respect of transactions to which *export transmission service* relates, and in respect of which charges are required to be collected by the *IESO* pursuant to section 3 of Chapter 10;

no margin call option means the option wherein a *market participant* elects, pursuant to Chapter 2, Section 5.6.4, to not be subject to *margin calls*;

non-committed resource means a *registered facility* that is neither - in whole or in part - rate-regulated, contracted to the *IESO*, contracted to the *OEFC*, or obligated as a resource backed capacity export to another jurisdiction during the entire duration of a given *obligation period*;

non-defaulting market participant means, for purposes of the imposition of the *default levy*, every *market participant* other than the *defaulting market participant* whose default in payment has triggered the imposition of the *default levy*;

non-dispatchable load means a load, within the *IESO control area*, that is not subject to *dispatch* by the *IESO* and whose level is not selected or set based on the price of *energy* in the *real-time market*;

normal operating state means the state described in section 2.2 of Chapter 5;

normal priority path facility means a voice communication facility that meets the requirements of section 1.1.8 of Appendix 2.2 of Chapter 2;

notice of default levy means a notice issued by the *IESO* to a *non-defaulting market participant* in accordance with section 8.2.3 or 8.4.1 of Chapter 2;

notice of disagreement means a notice provided by a *market participant* to the *IESO* in regard to a disagreement over a *preliminary settlement statement*;

notice of dispute has the meaning ascribed thereto in section 2.5.1 of Chapter 3;

notice of intent to suspend means a notice issued by the *IESO* to a *market participant* under section 6.3.3.1 of Chapter 3;

notice of intention means a notice issued by the *IESO* to a *market participant* under section 6.2B.2 of Chapter 3;

notice to elect shall be in such form as may be established by the *IESO* and means a written notice provided by the *market participant* to the *IESO* under section 6.2B.6 of Chapter 3;

NPCC means the Northeast Power Coordinating Council;

OEB or *Ontario Energy Board* means the Ontario Energy Board continued pursuant to section 4 of the *Ontario Energy Board Act, 1998*;

OEFC means the Ontario Electricity Finance Corporation established under Part V of the *Electricity Act, 1998;*

obligation period means the period of time for which a *capacity market participant* is required to fulfill its *capacity obligation* through the day-ahead commitment process and *energy market;*

offer means a statement of the quantities of a commodity that a seller will provide at different *market prices* for that commodity in the *real-time market,* the *procurement market,* or the *capacity auction*;

one-day advance approval means *IESO* approval of a *planned outage* of equipment no later than 14:00 EST on the *business day* prior to the scheduled start date of the *planned outage*;

Ontario electricity emergency plan means the plan describing the responsibilities of, and coordinating the actions of, *market participants* and the *IESO* for the purpose of alleviating the effects of an *emergency* on the *integrated power system*;

Ontario Energy Board Act, 1998 means the Ontario Energy Board Act, 1998, S.O. 1998, c. 15, Schedule B;

OPA or *Ontario Power Authority* means the Ontario Power Authority established under Part II.1 of the *Electricity Act, 1998*;

Ontario power system restoration plan means the detailed plan indicating how to re-energize the *IESO-controlled grid* or part of it in case the *IESO-controlled grid* or part of it collapses;

operating agreement means an agreement between the *IESO* and a *transmitter* which gives the *IESO* the authority to direct operations of the *transmitter's transmission system*, as contemplated in subsection 6(1)(b) of the *Electricity Act, 1998* and in subsection 70(2)(k) of the *Ontario Energy Board Act, 1998*;

operating deviation means the deviation described in section 3.8 of Chapter 9 between the performance of a *registered facility* and the performance required of that *registered facility* for the provision of *operating reserve*;

operating reserve means *generation capacity, electricity storage capacity* or load reduction capacity which can be called upon on short notice by the *IESO* to replace scheduled *energy* supply which is unavailable as a result of an unexpected *outage* or to augment scheduled *energy* as a result of unexpected *demand* or other contingencies;

operating reserve market means a *real-time market* in which *offers* to supply each class of *operating reserve* are cleared consistent with the *energy offers* and *energy bids*;

operating result means the physical quantity or quantities measured or estimated by the *IESO* as delivered by a *registered facility* during the actual operation of the *electricity system*;

outage means the removal of equipment from service, unavailability for connection of equipment or temporary derating, restriction of use, or reduction in performance of equipment for any reason including, but not limited to, to permit the performance of inspections, tests or repairs on equipment, and shall include a *planned outage*, a *forced outage* and an automatic *outage*;

over committed capacity means capacity has been contracted to or otherwise obligated to be provided to the *IESO*, the OEFC, or another *control area operator* at any time during a given *obligation period* where the same capacity is included in a *cleared ICAP* held by a *capacity market participant* participating with a *generator-backed capacity import resource;*

participation agreement means the agreement required to be executed between the *IESO* and each *market* participant pursuant to section 3.1.2 of Chapter 2 and pursuant to which the *IESO* and the *market participant* agree, among other matters, to be bound by the *market rules*;

participant technical reference manual means the document entitled "Participant Technical Reference Manual" and *published* by the *IESO*;

participant workstation means the communication equipment that is required to be maintained by *market participants* in accordance with Appendix 2.2 for the purposes referred to in section 1.4.1 of Appendix 2.2 of Chapter 2;

payment date means the date upon which payment is due;

per-start means the act of achieving synchronization to the *IESO-controlled grid*, ramping to the *minimum loading point* and operating at the *minimum loading point* until the end of the *minimum generation block run-time*;

performance adjustment factor means a value assigned to a *capacity auction resource* based on its historical performance during a *capacity auction capacity test* activation in the relevant summer or winter *obligation period* and is calculated in accordance with the process set out in the applicable *market manual;*

period of steady operation means a predefined number of intervals (0, 1, or 2) for which a non *quick-start* generation *facility* must maintain steady operation before changing direction of its *energy* output (either increasing or decreasing). Such a *facility* is considered to be in steady operation if the magnitude of change between *dispatch instructions* for the last two intervals is less than 0.1 multiplied by its ramp rate capability between the two intervals;

physical bilateral contract means an agreement between two parties, neither of which is the *IESO*, to trade a specified quantity of electricity at prices determined by the parties to the agreement, and pursuant to which the parties provide for the use of the *IESO settlement process* to account for *physical bilateral contract data*;

physical bilateral contract data means the data concerning a *physical bilateral contract* that a selling *market participant* provides to the *IESO* for purposes of *settlement*;

physical bilateral contract quantity means a quantity of *energy*, in MWh, that a *selling market participant* is selling to a *buying market participant* at a specified location and in a specified hour;

physical market means a *real-time market* and/or a *procurement market* administered by the *IESO* pursuant to Chapter 7;

physical service means the service of providing *energy* or *ancillary services*;

PJM means the Pennsylvania, New Jersey, Maryland Interconnection;

planned capability factor means the ratio of the *energy* which could have been delivered by a generating station with planned *generation unit* limitations in effect, to the *energy*, over the same period of time, that could have been delivered if the generating station had operated at its *maximum continuous rating*;

planned outage means an outage which is planned and intentional;

pre-dispatch day means the day prior to a *dispatch day*;

pre-dispatch schedule means an hourly schedule for the remaining hours of a *dispatch day* as determined by the *dispatch algorithm*;

pre-existing facility or equipment means a *facility* or equipment (i) that was or was part of a *facility* that was in existence on, and in respect of which a *licence* has been issued prior to, or

on, the date of coming into force of Chapter 4 of the market rules (April 17, 2000); or was in service on the date of coming into force of Chapter 4 of the *market rules* (April 17, 2000); and (ii) in respect of which an *exemption* has been applied for or granted relating to any of the following standards or obligations: (a) the technical requirements set out in Appendix 2.2 of Chapter 2 relating to voice communication, monitoring and control but not those relating to the *participant workstation* or *dispatch workstation*; (b) the technical requirements set out in Section 12 of Chapter 5 relating to communications; and (c) the grid *connection* and data monitoring requirements set out in Chapter 4 other than the requirements set forth in sections 6.1.5 to 6.1.21 of that Chapter.

preliminary settlement statement means the *IESO's* preliminary statement of the payments to be made by or to a *market participant* with respect to a given *billing period* and, in respect of the *settlement* of the purchase and sale of *transmission rights* in the *TR market*, the *IESO*'s preliminary statement of the payments to be made by or to a *TR holder* with respect to a given *TR auction* or the preliminary statement of the payments to be made by or to a *TR holder* with respect to a given *billing period*;

price-quantity pair means a price and an associated quantity that define a "step" in an *offer* or *bid* curve or an *EFM offer* or *EFM bid* curve;

primary RWM means an *RWM* that measures *meter data* regarding flows directly into or from the *IESO-controlled grid*;

procurement market means any one of the markets operated by the *IESO*, pursuant to Chapter 7, for contracted *ancillary services*, including *regulation, voltage control* and *reactive support services* and *black-start capability*, and for *reliability must-run contracts*;

prudential support means the obligations owed to the *IESO* by a third party and other forms of security or support for the financial obligations of a *market participant,* in the form set forth in section 5.7 of Chapter 2;

prudential support obligation means, in respect of a *market participant*, an amount equal to that *market participant's maximum net exposure* less any allowable reductions calculated in accordance with section 5.8 of Chapter 2;

pseudo-unit means a combined cycle *generation facility* that is modeled based on a gas-to-steam relationship between generation units, and which is comprised of one combustion turbine generation unit and a share of one steam turbine generation unit at the same combined cycle *generation facility*;

publish means, in respect of a document or information, to place that document or information on the *IESO's* web site, and publication shall be interpreted accordingly;

quarterly advance approval means *IESO* approval of a *planned outage* of equipment no later than the end of the month that is one month prior to the start of a six month period, starting with the next calendar quarter, in which the *planned outage* is scheduled to start;

quick start facility means a *generation facility* or an *electricity storage facility* whose electrical *energy* output can be provided to the *IESO-controlled grid* within 5 minutes of the *IESO's* request and is provided by equipment not synchronized to the *IESO-controlled grid* when the request to start providing *energy* is made;

radial intertie means a transmission line or lines which form part of the *IESO-controlled grid* and that: (a) connect an isolated portion of the *IESO control area* to an adjacent *control area;* or (b) connect the *IESO control area* to an isolated portion of an adjacent *control area,* in either case where the connected portion cannot, in accordance with an *operating agreement* or an *interconnection agreement,* be simultaneously connected to either another portion of one such *control area* or to a third *control area*;

reactive support service means a service provided by a *market participant* so as to allow the *IESO* to maintain the reactive power levels around the *IESO-controlled grid*;

real-time dispatch process is the process described in sections 7.1, 7.2, 7.3, and 7.4 of Chapter 7, when applied (i) while the *IESO-controlled grid* is in a *normal operating state;* and (ii) at a time other than when *market operations* have been suspended or *administrative prices* have been implemented;

real-time market means any one of the markets operated by the *IESO* for *energy*, *operating reserve* pursuant to Chapter 7;

real-time schedule means, in respect of a *registered facility* that is not a *boundary entity*, a *dispatch schedule* for a *dispatch interval* as determined by the *dispatch algorithm* and, in respect of a *registered facility* that is a *boundary entity*, the *interchange schedule* pertaining to that *registered facility*;

recalculated settlement statement means the *IESO*'s recalculated statement of the payments to be made by or to a *market participant* with respect to a given *billing period* and, in respect of the *settlement* of the purchase and sale of *transmission rights* in the *TR market*, the *IESO*'s recalculated statement of the payments to be made by or to a *TR holder* with respect to a given *TR auction* or the recalculated statement of the payments to be made by or to a *TR holder* with respect to a given *billing period*;

record of review means the document issued by the *IESO* to a *restoration participant* pursuant to section 11.4.1 of Chapter 5;

reference bus - the *RWM* on the basis of which the *IESO* determines, where applicable in accordance with section 3.6.2 of Chapter 9, the *energy market* price for the purpose of

determining the losses used in calculating contributions to the *transmission charge reduction fund*;

reference price means one or more of (i) a *historical reference price;* (ii) a price equal to the *market price* for *energy* determined for the *dispatch interval* in respect of which an *investigated price* was submitted; and (iii) such other *reference price* as may be established by the *IESO Board* pursuant to section 1.3.4 of Appendix 7.6 of Chapter 7;

registered facility means, in respect of a *facility*, a *facility* which is capable of supplying or withdrawing *physical services,* and which is registered with the *IESO* and means, in respect of a *boundary entity*, a *boundary entity* which is comprised of resources capable of supplying or withdrawing *physical services,* and is registered with the *IESO*;

registered market participant means a *market participant* that is registered with the *IESO* to submit *dispatch data* with respect to a *registered facility*;

registered wholesale meter or *RWM* means a *meter* that meets the criteria specified in Chapter 6 and that is registered with the *IESO.* References to a *registered wholesale meter* or *RWM* within Chapter 9 also include *meters* in *metering installations* whose registration has expired but the *IESO* determines that the continued use of the *metering installation* is necessary for the efficient operation of the *IESO-administered markets*;

regulation means the service required to control power system frequency and maintain the balance between load and generation;

release notification means in respect of a *variable generator* that is a *registered market participant,* a notification issued by the *IESO* providing that *energy* may be supplied from the *variable generation facility* to the *IESO-controlled grid* as ambient fuel conditions allow until a *dispatch instruction* is sent;

reliability means, in respect of electricity service, the ability to deliver electricity within *reliability standards* and in the amount desired and means, in respect of the *electricity system*, the *IESO-controlled grid*, the *integrated power system* or a *transmission system,* the ability of the *electricity system*, the *IESO-controlled grid,* the *integrated power system* or that *transmission system* to operate within *reliability standards* in an *adequate* and secure manner;

reliability must-run contract means a contract between the *IESO* and a *registered market participant* or prospective *registered market participant* for a *registered facility* that is or will be a *generation facility*, an *electricity storage facility,* a *dispatchable load facility* or a *boundary entity*, which allows the *IESO* to call on that *registered market participant's* or prospective *registered market participant's registered facility* in order to maintain reliability of the *IESO-controlled grid*;

reliability must-run resources means the resources described in section 4.8.1 of Chapter 5; these may also be referred to as *must-run resources*;

reliability standards means the criteria and standards, including an amendment to a standard or criterion, relating to the *reliable* operation of the *integrated power system* established by a *standards authority*, and declared in force subject to Chapter 5, sections 1.2.6 and 1.2.7, together with those set forth in these *market rules* or otherwise established by the *IESO* in accordance with these *market rules* and which has not otherwise been stayed or revoked and referred back to the *IESO* for further consideration by the *Ontario Energy Board*;

remaining duration of service means the remaining time it is expected that an *electricity storage facility* can continue injecting, or withdrawing, until it reaches its *lower energy limit,* or *upper energy limit*, respectively, assuming the *electricity storage facility* continues operating at its quantity offered or bid;

remedial action schemes or *RAS* means an automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system *reliability*. The term special protection system or SPS shall have the same meaning;

request for connection assessment means a request for the approval of a new *connection* to the *IESO-controlled grid* or of the modification of an existing *connection* to the *IESO-controlled grid* made pursuant to section 6.1.6 of Chapter 4;

Request for Segregation means a request from a *registered market participant* for approval to operate its *registered facility* in a *segregated mode of operation*;

reserve target means the minimum required MWs of any class of reserve required to satisfy reserve requirements;

respondent means a person against whom a complaint is made in a *notice of dispute*, a *response* or a response to a cross-claim;

response has the meaning ascribed thereto in section 2.5.4 of Chapter 3;

response to the notice of intention shall be in such form as may be established by the *IESO* and means a notice provided by the *market participant* under section 6.2B.3 of Chapter 3;

restoration participant means a *market participant* who has been identified by the *IESO* as having equipment or *facilities* that: (i) are directly connected to the *IESO-controlled grid* and (ii) affect the restoration process as set out in the *Ontario power system restoration plan*;

restoration participant attachment means the attachment to the *Ontario power system restoration plan* required to be prepared by a *restoration participant* and submitted to the *IESO* in accordance with section 11.3.5 of Chapter 5;

retail, with respect to electricity, means (a) to sell or offer to sell electricity to a consumer; (b) to act as agent or broker for a retailer with respect to the sale or offering for sale of electricity; or (c) to act or offer to act as an agent or broker for a *consumer* with respect to the sale or offering for sale of electricity;

retailer means a person who *retails* electricity;

revenue meter means a *meter* that is the designated source of *metering data* to be used by the *IESO* for *settlement* purposes in accordance with the *VEE process*;

review notice has the meaning ascribed thereto in section 4.4.2 of Chapter 3;

reviewable decision means a decision of the *IESO* referred to in section 2.1.2, 4.4.3, 5.1.12, 5.3.9 or 6.1.5 of Chapter 6 and sections 3.2A.1, 3.2A.5.3, 3.2A.10, 3.2B.5.3, 3.2B.7 or 3.2B.10 of Chapter 5;

RSS commencement date means the date on which market rule amendment MR-00475-R00 comes into effect;

schedule of record means the last valid set of results from the day-ahead commitment process used by the *IESO* for the application of constraints and the calculation of various day-ahead *settlement amounts*;

second contingency loss means an unexpected loss of a second component from the *electricity system* after the first component is already lost;

secretary means the secretary of the *dispute resolution panel* appointed pursuant to the *Governance and Structure By-law*;

security means the ability of the *electricity system,* the *IESO-controlled grid*, the *integrated power* system or a *transmission system* to withstand sudden disturbances including, without limitation, electric short circuits or unanticipated loss of equipment or components;

security coordinator, in respect of the *IESO-controlled grid*, means the *IESO* and, in respect of another *transmission system*, means the person responsible for coordinating the security of that *system* with that of other *transmission systems*;

security limits include operating *electricity system* stability limits and thermal ratings;

segregated mode of operation means an electrical configuration where a portion of the *IESO-controlled grid* is used to *connect* one or more *registered facilities* that are *generation*

facilities to a neighbouring *control area* using a *radial intertie* for the purposes of delivering electricity or *physical services* to such *control area*;

self-assessed trading limit means, in respect of a given *market participant*, the dollar amount determined by the *market participant* in accordance with section 5.3.2 of Chapter 2;

self-schedule means an hourly schedule specified by a *self-scheduling generation facility* or a *self-scheduling electricity storage facility,* and *self-scheduling* has an analogous meaning;

self-scheduling electricity storage facility means an *electricity storage facility* located within the *IESO control area* that can operate independently of *dispatch instructions* from the *IESO,* except for the provision of *regulation* services in respect of which it shall follow *dispatch instructions*;

self-scheduling generation facility means a *generation facility* located within the *IESO control area* that can operate independently of *dispatch instructions* from the *IESO*;

selling market participant means a *market participant* who is *selling energy* under a *physical bilateral contract*;

settlement means the process of transferring payments from those who are required to make payment to those who are required to be paid under the *market rules*;

settlement account means a bank account held by the *IESO*, a *market participant* or a *transmitter* pursuant to the *settlement* rules set forth in Chapters 8 and 9;

settlement amount means any amount of money to be paid by or to a *market participant,* determined in accordance with Chapter 9;

settlement hour means a period of one hour which corresponds to a particular *dispatch hour* for which *metering data* determined in accordance with Chapter 6 and *physical market prices* for services calculated pursuant to Chapter 7 are to be used to calculate the *settlement* debits and credits of *market participants*;

settlement process means any process administered by the *IESO* to effect *settlement*;

settlement statement means a *preliminary settlement statement*, a *final settlement statement*, and/or a *recalculated settlement statement*;

settlement statement re-calculation means the re-calculation of a *final settlement statement* during the attempted resolution of a *settlement* dispute;

short-term auction means a *TR auction* conducted by the *IESO* for the purchase and sale of *short-term transmission rights*;

short-term transmission right means a *transmission right* that is valid for a period of one month;

significant dispatchable load facility means a *dispatchable load facility* that includes a *dispatchable load* that is rated at 20 MVA or higher but less than 100 MVA; that comprises *dispatchable loads* the ratings of which in the aggregate equals or exceeds 20 MVA but is less than 100 MVA; or that is re-classified as a *significant dispatchable load facility* pursuant to section 1.5.1 or 1.5.2 of Appendix 2.2 of Chapter 2 or section 7.8.1 or 7.8.2 of Chapter 4;

significant electricity storage facility means an *electricity storage facility* that includes an *electricity storage unit* with an *electricity storage unit size* rated at 20 MVA or higher but less than 100 MVA; or that comprises multiple *electricity storage units*, the aggregated *electricity storage unit size* ratings of which equals or exceeds 20 MVA but is less than 100 MVA; or that is re-classified as a *significant electricity storage facility* pursuant to section 1.5.1A or 1.5.2A of Appendix 2.2 of Chapter 2 or section 7.8.2A or 7.8.2B of Chapter 4;

significant generation facility means a *generation facility* that includes a *generation unit* that is rated at 20 MVA or higher but less than 100 MVA; that comprises *generation units* the ratings of which in the aggregate equals or exceeds 20 MVA but is less than 100 MVA; or that is re-classified as a *significant generation facility* pursuant to section 1.5.1 or 1.5.2 of Appendix 2.2 of Chapter 2 or section 7.8.1 or 7.8.2 of Chapter 4;

single metering installation means a *metering installation* comprised of one *revenue meter*;

small distributor means, a *distributo*r with a projected *energy* consumption less than or equal to 0.25% of projected total system *energy* on an annual basis as determined by the *IESO* in accordance with the applicable *market manual*;

small electricity storage facility means an *electricity storage facility* that is comprised solely of an *electricity storage unit* with an *electricity storage unit size* rated at less than 1 MVA or that comprises multiple *electricity storage units*, the aggregated *electricity storage unit size* ratings of which is less than 1 MVA or that is re-classified as a *small electricity storage facility* pursuant to section 1.5.2A of Appendix 2.2 of Chapter 2 or section 7.8.2B of Chapter 4;

small generation facility means a *generation facility* that is comprised solely of a *generation unit* rated at less than 1 MVA or of *generation units* the ratings of which in the aggregate is less than 1 MVA or that is re-classified as a *small generation facility* pursuant to section 1.5.2 of Appendix 2.2 of Chapter 2 or section 7.8.2 of Chapter 4;

speed no-load cost is the hourly-value offered by the *registered market participant* to maintain a *generation facility* synchronized with zero net *energy* injected into the *IESO-controlled grid*;

SSPC means the *IESO* Settlement Schedule & Payments Calendar;

standards authority means NERC, NPCC, any successors thereof, and any other agency or body that approves standards or criteria applicable both in and outside Ontario relating to the *reliability* of *transmission systems*;

start-up cost is the value offered by the *registered market participant* to bring an off-line resource to its *minimum loading point*;

start-up time means the time in hours required to bring a *generation unit* or *electricity storage unit* on line. This is measured from the time of receiving a request to start the *generation unit* or *electricity storage unit* to the time of synchronization;

start volume means the incremental volume of fuel consumed by a *generation facility,* on a per registered resource basis, for an eligible real-time generation cost guarantee submission from either: (i) the point of ignition to the *minimum loading point* of the submitting eligible *registered facility*, on a per registered resource basis; or (ii) the point of synchronization to the *minimum loading point* of the submitting eligible *registered facility*, on a per registered resource basis, if operating in a full speed no-load state for more than five minutes in advance of synchronization to the *IESO-controlled grid*;

state of charge means the percentage of which an *electricity storage unit* is charged relative to the maximum registered *electricity storage energy rating* of the *electricity storage unit;*

station service means *energy* withdrawn from the *IESO-controlled grid* to power the on-site maintenance and operation of transmission *facilities*, *generation facilities, electricity storage facilities* and *connection facilities* located within the *IESO control area* but excludes *energy* consumed in association with activities which could be ceased or moved to other locations without impeding the normal and safe operation of the *facility* in question;

Statutory Powers Procedure Act means the *Statutory Powers Procedure Act,* R.S.O. 1990, c.S.22;

suspended market participant means a market participant that is the subject of a suspension order;

suspension order means an order issued pursuant to section 6.3A of Chapter 3 suspending all or part of the rights of a *market participant* to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid*;

system-backed capacity auction eligible import resource means a *capacity auction resource* associated with a *boundary entity* that is available to qualify capacity that a neighbouring *control area operator* is willing to allocate to Ontario, if a *capacity obligation* is secured, for

the duration of the applicable *obligation period*, which capacity would be deemed to be supplied from the entire system of the *neighbouring control area*. The allocated capacity must not otherwise be – in whole or in part – contracted to or otherwise obligated to be provided to the *IESO*, the *OEFC*, or another *control area operator* during the entire duration of a given *obligation period*;

system-backed capacity import resource means a *system-backed capacity auction eligible import resource* with a *capacity obligation* received in a given *capacity auction* in accordance with the applicable *market manual;*

target capacity means the amount of *auction capacity* which the *IESO* seeks to acquire through *a capacity auction*;

technical feasibility exception or *TFE* is a temporary exception from compliance with certain requirements of *NERC reliability standards* relating to critical infrastructure in accordance with Ontario-adapted *NERC* procedures for processing *TFEs*;

technical panel means the panel of the same name established pursuant to the *Governance and Structure By-law*;

ten-minute operating reserve means those *operating reserve*s required to respond fully within ten minutes of being called upon by the *IESO*;

terminated market participant means a market participant that is the subject of a termination order;

termination order means an order issued pursuant to section 6.4 of Chapter 3 terminating the rights of a *market participant* to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid*;

TFE applicant means (i) a *market participant* who applies to the *IESO* for a *TFE*; or (ii) a person applying to become a *market participant* who applies to the *IESO* for a *TFE*; or (iii) the *IESO*, in the event the *IESO* requires a *TFE*;

TFE application means an application for the approval, amendment, termination, or transfer of a *TFE* pursuant to section 3.2A of Chapter 5;

thirty-minute operating reserve means those *operating reserve*s required to respond fully within thirty minutes of being called upon by the *IESO*;

three-day advance approval means *IESO* approval of a *planned outage* of equipment no later than 16:00 EST on the third *business day* prior to the scheduled start date of the *planned outage;*

tieline means a transmission line which forms part of an *interconnection;* see *intertie*;

TR auction means an auction conducted by the *IESO* for the purchase and sale of *transmission rights*;

TR bid means a bid to purchase a *transmission right* in a *TR auction*;

TR bidder means a person that submits a *TR bid* to purchase a *transmission right* in a *TR auction*;

TR clearing account means the *settlement account* or fund established by the *IESO* and described in section 4.18.1 of Chapter 8;

TR holder means, in respect of a given *transmission right*, the *TR participant* recognized by the *IESO,* in accordance with section 4.3.1 or 4.9.5 of Chapter 8, as the *TR participant* that has the right to receive all *settlement amounts* under the *transmission right* or, in the case of a *long-term transmission right*, the right to receive all *settlement amounts* relating to one or more periods of one month under the *long-term transmission right*;

TR market means the market operated by the *IESO* for *transmission rights* pursuant to section 4 of Chapter 8;

TR market clearing price means, in respect of a given *transmission right*, the market clearing price for the *transmission right* established in accordance with section 4.15 of Chapter 8;

TR market deposit means the deposit required to be made by a *TR participant* pursuant to section 4.8.2 of Chapter 8 as a condition of being a *TR bidder* in a *TR auction*;

TR offer means an offer to sell a *transmission right* in a *TR auction*;

TR offeror means a person offering to sell a *transmission right* in a *TR auction*;

TR participant means a person that has been authorized by the *IESO* to participate in the *TR market* in accordance with section 4.8 of Chapter 8;

TR settlement price means, in respect of a *TR zone*, the *energy market* price for one MWh of *energy* in that *TR zone*, determined in accordance with section 3.1.3 of Chapter 9;

TR zone means the *IESO control area* or an *intertie zone* in respect of which the *IESO* calculates prices for *energy* for *settlement* purposes in the *real-time markets*;

trading day means a period from midnight EST to the following midnight EST within a *billing period*;

trading limit means, in respect of a given *market participant*, the dollar amount determined from time to time by the *IESO* for that *market participant* in accordance with sections 5.3.5 or 5.3.6 of Chapter 2;

trading week means seven consecutive *trading days* commencing on and including a Sunday;

transformation connection service means the *transmission service* relating to the use of the transformation connection assets of a *transmitter* whose *transmission system* forms part of the *IESO-controlled grid* and in respect of which charges are required to be collected by the *IESO* pursuant to section 6.1.1 of Chapter 10;

transitional scheduling generator means a *generation facility* located within the *IESO control* area that is under contract with *OEFC* effective April 1, 1999 and surviving the *market commencement date,* and is registered as such in accordance with the applicable sections of Chapter 7;

transmission charge reduction fund means the fund whose net proceeds are used to offset the charges levied on *market participants* for the recovery of the sunk and other costs of operating the *transmission systems* that make up the *IESO-controlled grid*;

transmission customer means a person, including but not limited to a *market participant*, that is required to pay for one or more *transmission services* pursuant to the terms of a rate order issued by the *OEB* to a *transmitter* whose *transmission system* forms part of the *IESO-controlled grid*;

transmission right or *TR* means a contractual right to receive a *settlement amount* determined in the manner described in section 4.4 of Chapter 8;

transmission service means any one or more of *network service*, *export transmission service*, *line connection service*, *transformation connection service* and such other service as may be approved by the *OEB* and in respect of which charges are required to be collected by the *IESO* pursuant to section 6A.1.1 of Chapter 10;

transmission services charges means all charges administered by the *IESO* to recover the costs of *transmission services*;

transmission services settlement account means a *settlement account* operated by a *transmitter* for the purpose of receiving payment of *transmission services charges* from the *IESO*;

transmission station service means *station service* associated with transformers, capacitors, switchgear, protection systems and control systems that are part of a transmission *facility* and that do not *connect generation facilities*, *electricity storage facilities, load facilities* or *distribution facilities* to the *IESO-controlled grid*;

transmission system means a system for transmitting electricity, and includes any structures, equipment or other things used for that purpose;

transmission tariff means a tariff fixed or authorised by the OEB in a rate order issued pursuant to the *Ontario Energy Board Act, 1998* with respect to the provision of *transmission services*;

transmission transfer capabilities means the measure, in terms of electric power expressed in megawatts, of the ability of *interconnected* electric systems to move or transfer power in a reliable manner from one area to another over all transmission lines or paths between those areas under specified system conditions.;

transmitter means a person who owns or operates a *transmission system*;

unattended means not *attended*;

unconstrained IESO-controlled grid model means the model capable of being used by the *dispatch algorithm* and described in section 4.5.1.1 of Chapter 7;

unforced capacity or *UCAP* means the maximum amount, in MW, that a *capacity auction participant* is able to *offer* for a *capacity auction resource* for an applicable *obligation period*, as calculated pursuant to section 18.2A.1 of Chapter 7*;*

upper energy limit means the highest energy amount to which an *electricity storage unit* can be consistently charged without damage beyond expected degradation from normal use;

urgent amendment, in relation to the market *rules*, means an *amendment* to the *market rules* made in accordance with section 34 of the *Electricity Act, 1998* on an urgent basis for any of the purposes noted in subsection 34(1) of the *Electricity Act, 1998*;

urgent rule amendment committee means the committee referred to in the *Governance and Structure By-law* and established by the Board of Directors of the *IESO* under the authority of the *Governance and Structure By-law* for the purpose of making *urgent amendments* to the *market rules*;

variable generation means all wind and solar photovoltaic resources with an installed capacity of 5MW or greater, or all wind and solar photovoltaic resources that are directly connected to the *IESO-controlled grid*;

variable generator means a *generator* whose *generation facility* is classified as *variable generation;*

VEE process means the process described in Chapter 9 and used to validate, estimate and edit raw *metering data* to produce final *metering data* or to replicate missing *metering data*;

VEE standard means that part of the *market manual* pertaining to *metering* entitled *Validating, Estimating, and Editing – Requirements for Validating, Estimating, and Editing Of Revenue Metering Data in the IESO-Administered Market*;

voltage control service means a service provided by a *market participant* so as to allow the *IESO* to maintain the voltage around the *IESO-controlled grid*;

Voltage reduction capability means the capability to reduce demand by lowering a customer's voltage. Within the *IESO-administered markets*, this capability is specifically defined as being able to reduce *distribution* or secondary voltages by 3% and 5%, and having the controlling authority to be able to effect that voltage reduction within five minutes of receipt of the direction from the *IESO* to do so;

wear and tear means, for the purposes of the Real-Time Generation Cost Guarantee Program, the useful life consumption of certain parts or equipment of a *generation facility* that would occur as a result of operation of the *generation facility* in accordance with prudent industry practices and original equipment manufacturer guidelines of the *generation facility*. The useful life consumption of certain parts or equipment of a *generation facility* manifests from applicable physical mechanisms (such as creep and fatigue) during different operating conditions (e.g. start-up, steady state operation, transients and shutdown);

weekly advance approval means *IESO* approval of a *planned outage* of equipment no later than 16:00 EST on the second Friday prior to the start of the week, starting Monday, in which the *planned outage* is scheduled to start;

wholesale consumer means a person who purchases electricity or *ancillary services* in the *IESO-administered markets* or directly from another person;

wholesale customer means a *market participant* who takes supply from the *IESO-controlled grid* for its own consumption or for sale;

wholesale seller means a person who sells electricity or *ancillary services* through the *IESO-administered markets* or directly to another person;

Exhibit "P"

IESO Market Manual 2.6: Treatment of Compliance Issues dated September 11, 2023

Exhibit "P"

to the Affidavit of Robin Doolittle

Sworn before me on October 29, 2025, in accordance with O. Reg. 431/20, Administering Oath or Declaration Remotely



Commissioner for Taking Affidavits
(or as may be)

October 29, 2025

Keith Edward Hickey, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.

Expires June 24, 2027.

PROCEDURE

ieso
Connecting Today.
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Market Manual 2: Market Administration

Part 2.6: Treatment of Compliance Issues

Issue 22

This procedure provides the steps required for the treatment of compliance issues by both Market Participants and the *IESO.*

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This *market manual* may contain a summary of a particular *market rule*. Where provided, the summary has been used because of the length of the *market rule* itself. The reader should be aware, however, that where a *market rule* is applicable, the obligation that needs to be met is as stated in the *market rules*. To the extent of any discrepancy or inconsistency between the provisions of a particular *market rule* and the summary, the provision of the *market rule* shall govern.

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Reference (Paragraph and Section)	Description of Change
S, 1.3.10	Removal of sentence regarding MACD not publishing a MACD determination if a market participant has initiated the dispute resolution process

Market Manuals

The *market manuals* consolidate the market procedures and associated forms, standards, and policies that define certain elements relating to the operation of the *IESO-administered markets*. Market procedures provide more detailed descriptions of the requirements for various activities than is specified in the *market rule*s. Where there is a discrepancy between the requirements in a document within a *market manual* and the *market rule*s, the *market rule*s shall prevail. Standards and policies appended to, or referenced in, these procedures provide a supporting framework.

Market Procedures

The "Market Administration Manual" is Volume 2 of the *market manual*s, where this document forms Part 2.6: "Treatment of Compliance Issues".

A list of the other component parts of the "Market Administration Manual*"* is provided in Part 2.0: *"*Market Administration Overview", in Section 2, "About This Manual".

Structure of Market Procedures

Each market procedure is composed of the following sections:

1. **"Introduction"**, which contains general information about the procedure, including an overview, a description of the purpose and scope of the procedure, and information about roles and responsibilities of the parties involved in the procedure.
2. **"Procedural Work Flow"**, which contains a graphical representation of the steps and flow of information within the procedure.
3. **"Procedural Steps"**, which contains a table that describes each step and provides other details related to each step.
4. **"Appendices"**, which may include such items as standards, policies, agreements, and list of forms.

Conventions

The *market manual* standard conventions are as defined in the "Market Manual Overview" document.

Definitions and Acronyms

A list of terms and acronyms used in this *market manual* is found in Chapter 11 of the *market rule*s. Unless otherwise defined in this *market manual*, terms and acronyms used in this *market manual* have the meanings ascribed thereto in Chapter 11 of the *market rule*s.

– End of Section –

1. Introduction

1.1 Purpose

This procedure describes the activities required for the treatment of compliance issues. It sets out the processes by which the *IESO* shall assess and enforce compliance with the *market rules*, and specifically:

- the treatment of alleged breaches of the *market rules* by a *market participant*;
- the suspension of a *market participant* following an *event of default*; and
- the termination of a *market participant* or de-registration of *facilities*.

The procedure is intended to provide a summary of the steps involved, particularly those affecting *market participants*, and to provide a summary of the interaction between *market participants*, the *IESO*, and other parties as related to this process.

1.2 Scope

This procedure is intended to provide *market participants* with a summary of the steps and interfaces between *market participants*, the *IESO*, and other parties for the treatment of compliance issues. Procedural work flows and procedural steps described in this document will serve as a roadmap for *market participants* and the *IESO*, and reflect the requirements set out in the *market rules* and applicable *IESO* policies and standards. The overview information in Section 1.3, below, is provided for context purposes only, highlighting the main actions that comprise the procedure.

The processes outlined in this procedure do not address the management of *events of default* relating to *prudential support* or payments due the *IESO*. The processes surrounding *events of default* relating to *prudential support* are addressed in the "Market Manual 5: Settlements, Part 5.4: Prudential Support". The processes surrounding *events of default* relating to payments due the *IESO* are addressed in the "Market Manual 5: Settlements, Part 5.9: Payment Methods and Schedule".

The process outlined in this document does not address market surveillance. This is addressed in "Market Manual 2: Part 2.7: Treatment of Market Surveillance Issues". The process outlined in this document does not address de-registration. This is addressed in "Market Manual 1: Market Entry, Maintenance and Exit, Part 1.2: Facility Registration, Maintenance and De-registration".

1.3 Overview

1.3.1 Ring-Fencing of Compliance Enforcement within the IESO

The *IESO* has assigned responsibility for the enforcement of compliance with the *market rules* to a separate business unit within the company, the Market Assessment and Compliance Division (MACD). MACD has delegated authority to independently exercise the discretion allowed to the *IESO* in Chapter 3, sections 6.2 and 6.6 of the *market rules*. It enforces compliance against both *market participants* and the *IESO*, operating in a ring-fenced structure within the *IESO* with its files and investigative information accessible only to MACD staff members.

1.3.2 Identification and Screening of Compliance Issues

The *IESO* or parties other than the *IESO* (which could include a *market participant*, a third party, or regulatory authorities) may report a suspected compliance issue. A compliance issue can be either an *event of default* or a breach of the *market rules*. An "*Event of Default"* is defined in Chapter 3, section 6.3 of the *market rules*, the current version of which is reproduced in Appendix B. *Events of default* relate predominantly to financial and legal matters, including, but not limited to, *prudential support*, licencing, liquidity, and insolvency.

MACD assesses whether the reported issue appears to constitute a breach and, if so, decides whether to issue an informal notice or a "Notice of Alleged Breach". Informal notices, called "Request for Information" and "Market Rule Reminders", are used when the apparent breach is assessed as having a low impact on the market or system and some other extenuating circumstance is recognized, such as the apparent breach was committed by a new *market participant* or one with a good compliance history. The "Market Rule Reminder*"* serves as notice to the party of the obligation and that continued or future non-compliance will likely be subject to investigation and sanction.

With the exception of cases pertaining to potential breaches of *reliability standards* or severe breaches*,* MACD will send the *market participant* or *IESO* an informal "Request for Information" prior to issuing a "Notice of Alleged Breach". This assists MACD in understanding the facts and may lead to a case being closed or handling it through a "Market Rule Reminder*"*. It may also provide better grounding for MACD to proceed formally by issuing a written "Notice of Alleged Breach".

1.3.3 Breach of Market Rules

Where a breach of the *market rules* is alleged and sanctions may be applied, MACD issues a "Notice of Alleged Breach" in accordance with Chapter 3, section 6.2.3 of the *market rules*, to the *IESO* or *market participant* that is alleged to have committed the breach, outlining:

- details of the alleged breach;
- details of the evidence on which MACD reached its determination;
- details of potential sanctions that may be imposed if it is established that a breach did in fact occur;

- the time within which the *market participant* may submit a written *response* to the notification; and
- the right of the *market participant* to request a meeting with MACD to discuss the alleged breach within an acceptable timeframe.

MACD may issue a "Notice of Alleged Breach" with conditions that specify that the investigation will be concluded with no finding of breach provided the party corrects the cause of the breach and comes into compliance by a stipulated date.

Where MACD, taking into account representations made, determines that the *market participant* or the *IESO* has breached the *market rules*, it may order the offending party to do one or more of the following:[1]

- such things as may be necessary to comply with the *market rules* within a specified period;
- cease within a specified period the act, activity or practice constituting the breach; or
- carry out additional or more stringent record-keeping or reporting requirements.

MACD may also issue a written "Notice of Non-Compliance" and impose a financial penalty on the *market participant* or a voluntary payment on the *IESO*.[2] These financial sanctions cannot be imposed unless MACD is satisfied that the breach could have been avoided by the exercise of due diligence or that the offending party acted intentionally.

In addition to these remedies, where a *market participant* has been found to be in breach of the *market rules* on a persistent basis, the *IESO* may issue a *disconnection* or *termination order*, cancel the registration of some or all of the *market participant's registered facilities*, or restrict its participation in the *IESO-administered markets* or the *IESO-controlled grid*.

Finally, once MACD determines that a breach has been committed, details including the name of the breaching party, the provision breached and any sanctions applied may be *published* on the sanctions page of the *IESO* Web site.

The amount of the financial penalty or voluntary payment is determined based on the rule breached as set out in Chapter 3, section 6.6 of the *market rules*. Rule breaches fall into three penalty categories. Most fall within a specified range based on the selected level of non-compliance. The non-compliance level range maximums are $2,000, $4,000, $6,000 and $10,000 per breach. The range maximums may be exceeded if one or more of the defined circumstances, set out in Chapter 3, section 6.6.6A of the *market rules*, are met. Finally, a handful of provisions identified in Appendix 3.1 are subject to formula-based penalties that take into consideration the duration of the breach, a measure of the deviation from the obligation and a multiple of the prevailing *market price*.

[1] The *market rules* also provide for specific additional remedies as a result of breaches of certain provisions. These include declaring that a facility is 'non-conforming' where *market participants* do not follow *dispatch instructions*, withholding a *Transmission Right* (*TR*), where payment is not made for the *TR*. This *market manual* does not seek to provide a comprehensive listing of the potential actions that the *IESO* may undertake following the occurrence of such breaches.

[2] The *IESO* is required to comply with the *market rules* (Chapter 1, section 5.4.1) and has undertaken to be treated as if it were a *market participant* because it is not named in the investigative and enforcement provisions in Chapter 3. Voluntary payments are assessed against the *IESO* on the same basis as financial penalties however the amounts are deposited in the *IESO adjustment account* and allocated by the *IESO Board* to special education projects or initiatives (Chapter 9, section 6.18.6).

1.3.4 Sanctions: Financial Penalties

Formula Based Financial Sanctions

The formula for the financial penalty is defined in of Chapter 3, section 6.6.8 of the *market rules*:

P= D x T x C

Where 'P' is the penalty to be imposed in dollars, 'D' is the deviation of the relevant quantity in the applicable obligation, 'T' is the duration of the breach, expressed in hours or fractions of hours, and 'C' is an amount determined by multiplying the clearing price by a factor relating to the breach and associated considerations.

1.3.5 Financial Penalties- Not Formula Based

Where the Appendix 3.1 provides for "Sanctions as per Section 6.6.6", or where a *market participant* has not complied with an order previously issued for a breach, MACD must determine whether to issue a non-compliance letter or impose a financial penalty. MACD's decision is based on the level of compliance and rate of recurrence.

The level of non-compliance is determined on the basis of degree of compliance, how MACD became informed of the breach, and the responsiveness of the *market participant* with a remedy. This is summarized in the following table:

Levels of Non-Compliance & Penalty Ranges in section 6.6.6

Compliance with all requirements of market rule	Informed the IESO on own initiative and on timely basis	Provided reasons for non-compliance, and plan (manner and time) to remedy	Level of non-compliance	Range of Financial Penalty
In part but not in whole	Yes	Yes	L1	Up to $2,000
Neither in whole nor part	Yes	Yes	L2	Up to $4,000
Neither in whole nor part	No	Yes, upon request of IESO and within requested time	L3	Up to $6,000
Neither in whole nor part	No	No	L4	$1,000 to $10,000

If a *market participant* meets some but not all of the requirements of a single level or proposes a remedy that is not reasonable in time or manner, MACD will assign the level it considers to be appropriate. The level of the penalty may be revised as information is gathered through the investigation.

MACD may impose a financial penalty in excess of the maximum of the ranges in the preceding table up to $1,000,000 per occurrence as set out in Appendix E: Sanctioning Guidelines.

Penalty Matrix in section 6.6.6B

	Non-Compliance Level (Severity and Breach History)							
Impact Level	**Low**		**Moderate**		**High**		**Severe**	
	Range Limit		Range Limit		Range Limit		Range Limit	
	Min	Max	Min	Max	Min	Max	Min	Max
Low Little or None	$2,000	$25,000	$2,000	$50,000	$3,000	$75,000	$5,000	$100,000
Medium Material	$2,000	$100,000	$4,000	$250,000	$6,000	$450,000	$10,000	$600,000
High Severe	$4,000	$250,000	$8,000	$500,000	$12,000	$750,000	$20,000	$1,000,000

To determine the amount of the financial sanction within the ranges in either of the two above tables, MACD weighs the factors listed in section 6.6.7 of the *market rules* in relation to the facts of the case:

- the circumstances in which the breach occurred;
- the severity of the breach;
- the extent to which the breach was inadvertent, negligent, deliberate or otherwise;
- the length of time the breach remained unresolved;
- the actions of the *market participant* on becoming aware of the breach;
- whether the *market participant* disclosed the matter to the *IESO* on its own or whether it was prompted to do so;
- any benefit that the *market participant* obtained or may have obtained as a result of the breach;
- any previous breach by the *market participant* of the *market rules* or of the conditions of its *licence*;
- the actual or potential impact of the breach on other *market participants*;
- the actual or potential impact of the breach on the *IESO-administered markets* as a whole;
- the actual or potential impact of the breach on the *reliability* of the *integrated power system*;

- any sanctions that may be imposed on the *IESO* by a *standards authority* as a result of the breach;
- the immediacy of the threat that the breach poses to the *reliability* of the *integrated power system* or the *IESO-administered market*;
- presence and quality of the *market participant*'s compliance program;
- whether on its own initiative, a *market participant* has undertaken to reasonably compensates the *IESO-administered market* for the value of any benefit it obtained as a result of the breach; and
- such other matters as the *IESO* considers appropriate.

1.3.6 Voluntary Payment

In deciding whether to issue an informal notice or a "Notice of Alleged Breach" and in fixing the amount of any financial penalty, MACD will consider whether on its own initiative, a *market participant* has undertaken to reasonably compensate the *IESO-administered market* for the value of any benefit it obtained as a result of the breach. To make a voluntary payment a *market participant* should send a request to the *IESO* at:

The IESO
Market Assessment and Compliance
655 Bay Street, Suite 410
P.O. Box 1
Toronto, ON M5G 2K4
Fax No.: (905) 855-6408
Email Address: MACD@ieso.ca
Attention: Settlements Department
Subject: Voluntary Payment

The request should include

- the compliance case reference number (COM0XXXXX) if applicable,
- request to have the payment processed on the next available month end *settlement* statement, and
- a spreadsheet or table showing the amount to be paid by *charge type* and *delivery point* (if applicable).

The request should be made by a contact registered with the *IESO* and copied to the *market participant's settlement* department and *settlement* contact.

1.3.7 Persistent Breaches of the Market Rules

If a *market participant* has breached the *market rules* on a persistent basis the *IESO* may:

- issue the *market participant* a *suspension order*,
- issue the *market participant* a *termination order*, or
- deregister some or all of the *market participant's registered facilities*.

Where the *IESO* intends to undertake any of the above the *IESO* will provide the *market participant* with a notice stating:

- the nature of the action to be taken;
- the grounds and any evidence on which the *IESO* relies on in support of the intended action;
- the time within which the *market participant* may make written representations to the *IESO* as to why such action should not be taken; and
- the right of the *market participant* to request a hearing before the *IESO Board* or a committee of the *IESO Board* established for such purpose to show cause why such action should not be taken.

A copy of the notice issued to the *market participant* will be copied to the *OEB* and to the *transmitter, distributor* and/or other *market participant* to whose *facilities* the *market participant's facilities* who is the subject of the notice are *connected.*

The *market participant* may request a hearing before the *IESO Board* providing the *market participant* with a reasonable opportunity to show cause as to why such action should not be taken. Following the hearing, the *IESO Board* may:

- approve the action that the *IESO* intends to take; or
- make any other appropriate order.

If the *market participant* does not request a hearing, the *IESO* shall consider any written representations received from the *market participant.* The *IESO* shall *publish* a notice of any actions taken and provide a copy to the *OEB* and the *transmitter*, *distributor* and/or other *market participant* to whose *facilities* the *market participant's facilities* are *connected*.

1.3.8 Suspension of Market Participant

A *suspension order* may be issued by the *IESO* for persistent breaches of the *market rules* or when an *event of default* by a *market participant* has not been remedied within the time frame prescribed in the *notice of intent to suspend*, or when an *event of default* related to a court supervised proceeding such as a bankruptcy protection or receivership has occurred.[3] A *disconnection order* may also be issued at the same time the s*uspension order* is issued. The *disconnection order* is issued to the *transmitter(s)* or *distributor(s)* and/or other *market participant* to whose *facilities* the *suspended*

[3] The processes surrounding *events of default* relating to *prudential support* are addressed in "Market Manual 5: Settlements, Part 5.4: Prudential Support." The processes surrounding *events of default* relating to payments due the *IESO* are addressed in "Market Manual 5: Settlements, Part 5.9: Payment Methods and Schedule".

market participant's facilities are *connected*. A copy is provided to the *OEB*. The *disconnection order* orders the *transmitter(s)* or *distributor(s)* to *disconnect* the *market participant* to prevent unauthorized access to the *IESO* system.

Where a *market participant* commits an *event of default*, the *IESO* may issue a "*Notice of Intent to Suspend*" to the *defaulting market participant* stating that the *market participant* will be suspended unless it remedies the *event of default* within 2 *business days* or such longer period as specified in the notice.

The *IESO*- may issue a *suspension order* to a *market participant* if the *market participant*:

- has not remedied an *event of default* within the time specified in the *notice of intent to suspend*;
- ceases or threatens to cease to carry on its business or a substantial part of its business;
- becomes insolvent or is unable to pay all or some of its debts when they fall due for payment;
- seeks to enter into an arrangement, composition or compromise with, or makes an assignment for the benefit of, all or any class of its creditors;
- has a receiver or receiver and manager or person having a similar or analogous function under the laws of any relevant jurisdiction appointed in respect of any of its property that is used in or relevant to the performance of its obligations under the *market rules* or its *licence*;
- is the subject of an order appointing an administrator, liquidator, trustee in bankruptcy or person having a similar or analogous function under the laws of any jurisdiction;
- is wound up, dissolved, or otherwise has ceased to exist or is the subject of an application for winding up or dissolution, or any analogous procedure, under the laws of any jurisdiction, unless the notice of winding up or dissolution is discharged or withdrawn;
- ceases to satisfy any material requirement imposed upon it as a condition of its authorization to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid*; or
- has been determined by the *IESO* to have persistently breached the *market rules*.

The *IESO* shall *publish* the details of the *suspension order* and provide a copy of the *suspension order* to the *OEB* and the *transmitter, distributor* and/or other *market participant* to whose *facilities* the suspended *market participant* is *connected*.

When the *IESO* issues a *suspension order* to a *market participant,* the *suspended market participant* becomes ineligible to trade or enter into any transaction in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid*, to the extent specified in the *suspension order*. This condition remains until the *IESO* notifies the *suspended market participant*, and all other *market participants*, that the *suspension order* has been lifted.

The *market rules* require that the *IESO* make a public announcement, providing details of the suspension, and that the *IESO* issue a public notice promptly after a *suspension order*, and where applicable, a *disconnection order* is lifted, extended, modified or stayed.

The *suspension order* would normally include;

- details on the *market participant*'s rights being suspended;
- the date upon which the suspension becomes effective;
- the *market participant's* obligations under the *suspension order*;
- the actions required in order for the *suspension order* to be lifted; and
- if applicable, notification to the *market participant* that a *disconnection order* has been sent to *transmitter (s)* or *distributor(s)* and/or other *market participant* to whose *facilities* the suspended *market participant* is *connected.*

On issuing a *suspension order* to a *market participant* the *IESO* may give effect to the order by;

- rejecting any *bid* or *offer* submitted by the *suspended market participant*;
- setting-off any amounts otherwise due to the *suspended market participant* against any amounts owed by the *suspended market participant* under the *market rules*;
- issuing a *disconnection order* to the *transmitter, distributor* and/or other *market participant* to whose *facilities* the *suspended market participant's facilities* are connected; or
- making such further order or issue such directions to the *suspended market participant* as the *IESO* determines appropriate.

Where the *event of default* that triggered the issuance of a *suspension order* is remedied and there are no other *events of default* in existence with respect to the *suspended market participant*, the *IESO* shall lift the *suspension order* and, if applicable, cancel the *disconnection order.*

The *IESO* may, as a condition of lifting a *suspension order*, impose such conditions on the authorization of the *market participant* to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid*, as the *IESO* determines appropriate. These may include, but are not limited to:

- establishing a lower *trading limit* in respect of the *market participant* than would otherwise be the case under of Chapter 2, section 5.3 of the *market rule*s;
- establishing a more frequent continuing schedule of payments than would otherwise be the case under Chapter 9 of the *market rules*; or
- imposing more stringent *prudential support* requirements than would otherwise be the case under of Chapter 2, section 5 of the *market rules.*

1.3.9 Termination of Market Participant

Market participants may have their rights terminated if they are in persistent breach of the *market rules*, or if they fail to remedy the *event of default* that triggered a *suspension order*.

The *IESO* may issue a *termination order* to a *market participant* if:

- the *market participant* is a *suspended market participant* and has not remedied the *event of default* that triggered the *suspension order* within 5 *business days* of the issuance of the *suspension order*;
- the *market participant* is a *suspended market participant* and has notified the *IESO* that the *market participant* is not likely to remedy the *event of default* that triggered the issuance of the *suspension order*;
- the *market participant* has been wound up, dissolved, or otherwise has ceased to exist; or
- the *IESO* has determined that a *termination order* should be issued because the *market participant* has persistently breached the *market rule*s.

At the same time that a *termination order* is issued to the *market participant*, a *disconnection order* may be issued to the *transmitter(s)*, *distributor(s)* or other *market participant to* whose *facilities* the *market participant* is *connected* and a copy provided to the *OEB*. The *disconnection order* directs the *transmitter*(s), *distributor(s)* or other *market participant* to *disconnect* the *facilities* on the date and at the time specified in the *disconnection order*.A terminated *market participant* remains subject to and liable for all of its obligations and liabilities as a *market participant* under the *market rules*. A terminated *market participant* who wishes to be re-admitted as a *market participant* to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid,* shall be required to re-apply for authorization.

The *IESO* may impose such terms and conditions on the rights of the *terminated market participant* that re-applies for authorization to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid* as the *IESO* determines appropriate in the circumstances, whether or not such terms and conditions are otherwise applicable to other *market participants*.

1.3.9A De-Registration of a Market Participant's Facilities

Market participants may have some or all of their *facilities* de-registered if they are in persistent breach of the market rules.

The *IESO* may issue a de-registration order to a *market participant* if the *IESO* has determined that the *market participant* has persistently breached the market rules.

At the same time that a de-registration order is issued to the *market participant*, a *disconnection order* may be issued to the *transmitter(s)*, *distributor(s)* or other *market participant* to whose *facilities* the *market participant* is *connected* and provide a copy to the *OEB*. The *disconnection order* directs the *transmitter*(s), *distributor(s)* or other *market participant* to *disconnect* the *facilities* on the date and at the time specified in the *disconnection order*.

A *market participant* who wishes their *facility* or *facilities* to be re-registered shall be required to re-apply for *facility* registration.

The *IESO* may impose such terms and conditions on the rights of the *market participant* to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid* as the *IESO* determines appropriate in the circumstances, whether or not such terms and conditions are otherwise applicable to other *market participants*.

1.3.10 Public Reporting of Breaches of Market Rules

Public reporting as per Chapter 1, section 9.1.1 and 9.1.2 of the *market rule*s "…shall be effected by placing the document or information on the *IESO* Web site. The document or information shall be deemed to be *published* when the document or information has been so placed." Where, due to *market rules*, *licence* of the *IESO* or other *applicable laws* or bylaws, the *IESO* must *publish* in an alternate mode to that listed above, the *IESO* will comply with that requirement by *publishing* in the alternate mode and on the *IESO* Web site.

Where a *market participant* has been found to be in breach of the *market rules* by MACD and a sanction, financial or otherwise, has been assessed, the *IESO* may *publish* the name of the offending party and other information relating to the breach in accordance with "Market Manual 2.0: Market Administration, Part 2.14 Information Confidentiality Catalogue". Disclosure of information regarding the disputed matter or other related information may be required by the dispute resolution process in accordance with "Market Manual 2: Market Administration, Part 2.1: Dispute Resolution".

In cases where a *market participant* had been alleged to be in breach of the *market rules* but subsequently not found to be in breach by MACD, no public reporting of the alleged breach shall occur.

A complete list of *confidentiality classification* is available in "Market Manual 2: Part 2.14: Information Confidentiality Catalogue".

1.4 Roles and Responsibilities

Responsibility for carrying out the "Treatment of Compliance Issues" procedure is shared among:

- ***Market participants***, who are responsible for:
  - notifying the *IESO* if they are in breach of the *market rules* or have triggered an *event of default;*
  - complying with orders and directions issued by the *IESO*;
  - providing information to, or meeting with, the *IESO*, as requested;
  - requesting a meeting or hearing, as appropriate based upon *IESO* action;
  - responding to a notification of an alleged breach of the *market rules*, if desired; and
  - requesting suspension, termination or de-registration hearings.
- The ***IESO***, which is responsible for:
  - monitoring *market participant*s for compliance with the *market rules* and identifying compliance issues;
  - taking immediate action if *security* or *reliability* may be compromised by a compliance issue;
  - requesting information needed for a compliance investigation and meeting with the *market participant*, where requested;

- conducting investigations and determining the appropriate action in *response* to the compliance issue;
- notifying the *market participant* of investigation findings and evaluating the *market participant response*;
- conducting a suspension, termination or de-registration hearings, if requested by a *market participant*;
- issuing orders arising from a breach of the *market rules* by a *market participant*; and
- acting as a repository for information concerning breaches of *market rules* for future use in compliance investigations.

1.5 Contact Information

As part of the *participant* authorization and registration process, *applicants* are able to identify a range of contacts within their organization that address specific areas of market operations. For compliance issues, this contact will most likely be the Non-Compliance Market Contact Type in PLC – Participant Life Cycle (*market participant* contacts screen). If a *market participant* has not identified a specific contact, the *IESO* will seek to contact the main contact in PLC that is established during the *participant* authorization process. The *IESO* will seek to contact these individuals for activities within this procedure, unless alternative arrangements have been established between the *IESO* and the *market participant*. For more information on PLC and the *participant* authorization process see "Market Entry, Maintenance and Exit, Part 1.1 – Participant Authorization Maintenance and Exit."

If the *market participant* wishes to contact the *IESO*, the *market participant* can contact the *IESO* Customer Relations via email at customer.relations@ieso.ca or via telephone, mail or courier to the numbers and addresses given on the *IESO's* Web site (www.ieso.ca - or click on 'Have a question?' to go to the 'Contacting the *IESO*' page). If the *IESO* Customer Relations is closed, telephone messages or emails may be left in relevant voice or electronic *IESO* mail boxes, which will be answered as soon as possible by Customer Relations staff.

Standard forms that *market participants* must complete for this procedure are listed in Appendix A. These forms are generally available for downloading on the *IESO*'s public Web site. These forms as well as the accompanying supporting documentation must be transmitted to the *IESO* via email, mail, fax or courier, by using the appropriate address or number provided on the *IESO*'s public Web site or on the form.

– End of Section –

2. Procedural Work Flow

The diagrams in this section represent the flow of work and information between the *IESO*, the non-compliant *market participant* involved in the process, and any other parties related to the treatment of compliance issues.

The steps illustrated in the diagrams are described in detail in Section 3 below.

Table 2–1: Legend for Work Flow Diagrams

Legend	Description
Oval	An event that triggers task or that completes task. Trigger events and completion events are numbered sequentially within procedure (01 to 99)
Task Box	Shows reference number party responsible for performing task (if "other party"), and task name or brief summary of task. Reference number (e.g., 1A.02) indicates procedure number within current *market manual* (1), sub-procedure identifier (if applicable) (A), and task number (02)
Solid horizontal line	Shows information flow between the *IESO* and external parties
Solid vertical line	Shows linkage between tasks
Broken line	Links trigger events and completion events to preceding or succeeding task

2.1 Identification of Compliance Issues

When a non-compliance event has been identified, MACD may notify the non-compliant party and request that the behaviour causing the non-compliance be corrected. MACD will then determine the type of non-compliance event that has been identified prior to taking the appropriate actions (as set out in Sections 2.2, 2.3 and 2.4).

The steps shown in Figure 2–1 are described in detail in Section 3.1, Table 3–1.

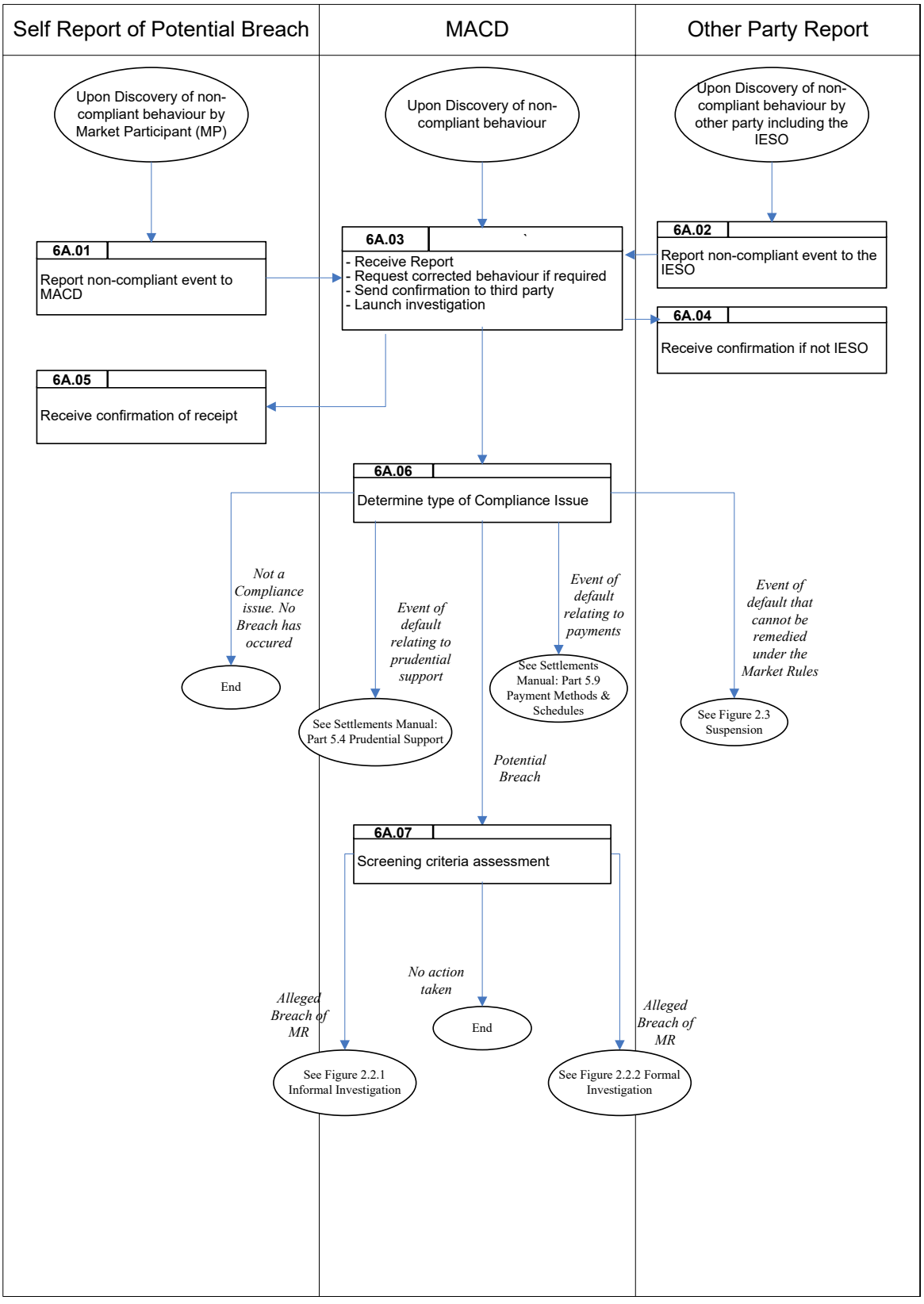


Figure 2–1: Work Flow for the Identification of Compliance Issues

2.2 Treatment of Alleged Breach of the Market Rules

Where MACD determines that a compliance issue is an alleged breach of the *market rules*, it will conduct an investigation to confirm (or otherwise dismiss) the breach. As part of this investigation it will seek information from the non-compliant *market participant* and the party reporting the compliance issue and, on request, meet with the party potentially in breach to review the evidence presented. Where a breach is confirmed, MACD will apply appropriate sanction to the party in breach.

The steps shown in Figure 2–2 are described in detail in Section 3.2, Table 3–2.

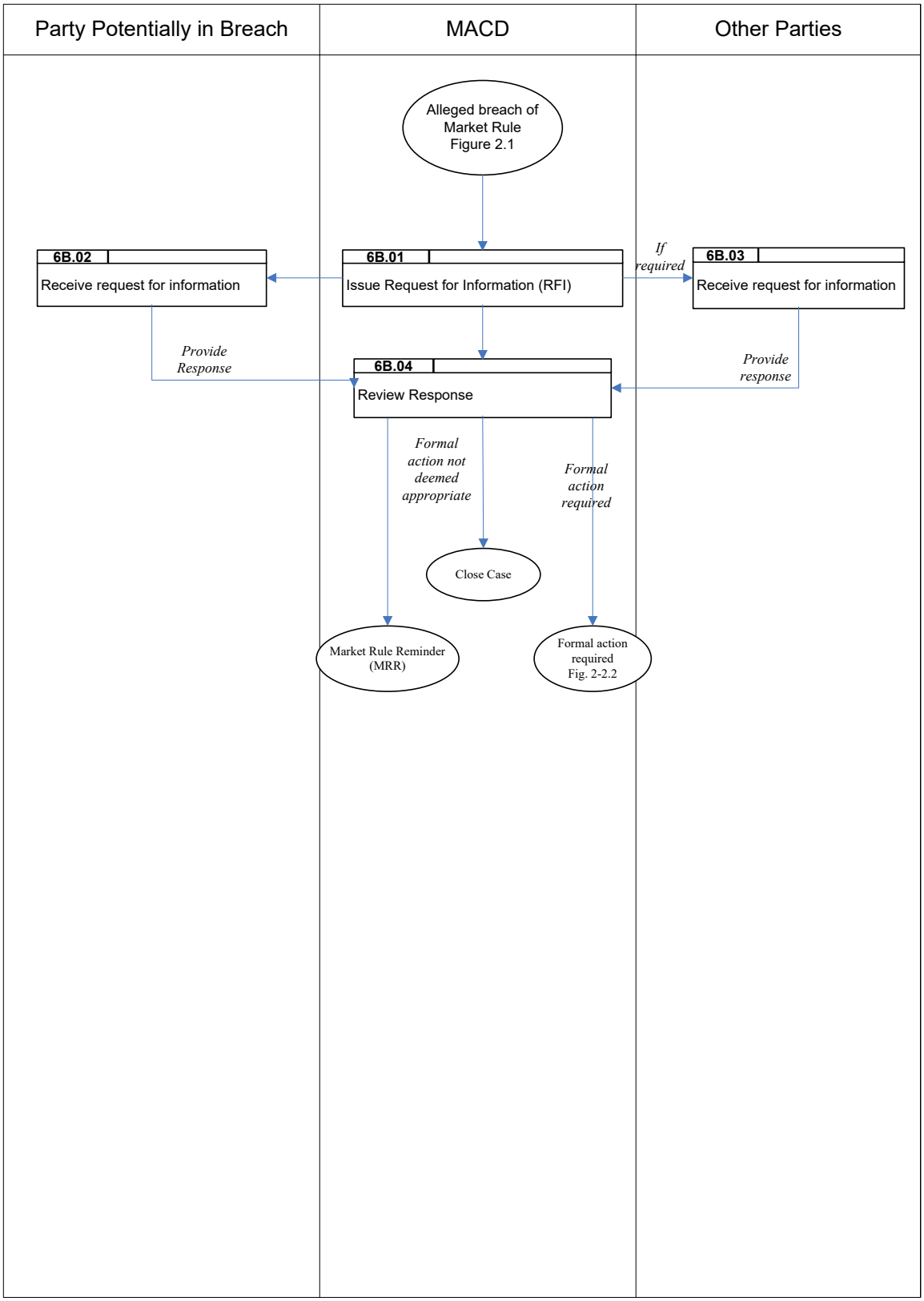


Figure 2–2.1: Work Flow for the Treatment of Alleged Breach of the Market Rules – Informal Process

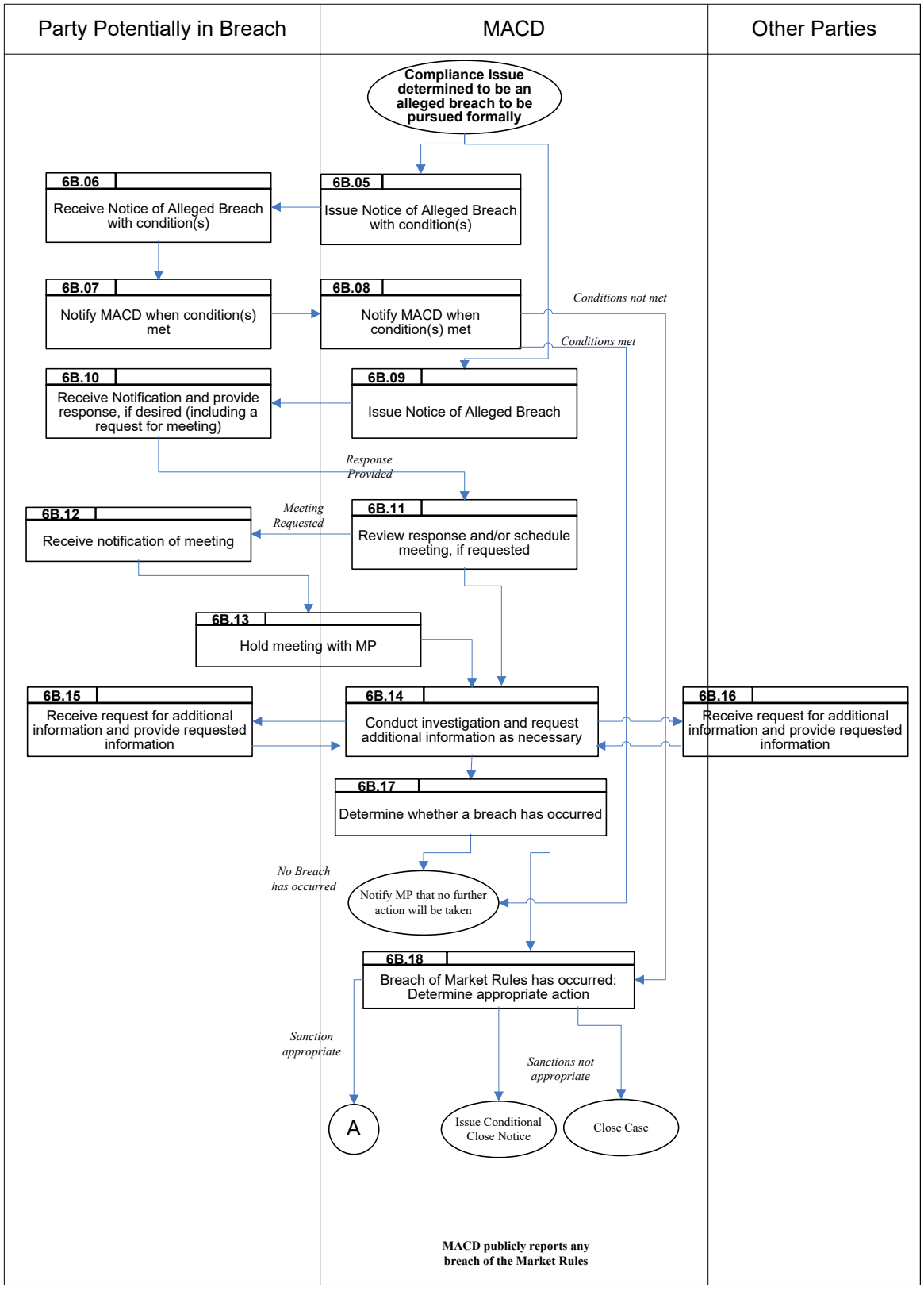


Figure 2–2.2: Work Flow for the Treatment of Alleged Breach of the Market Rules – Formal Process

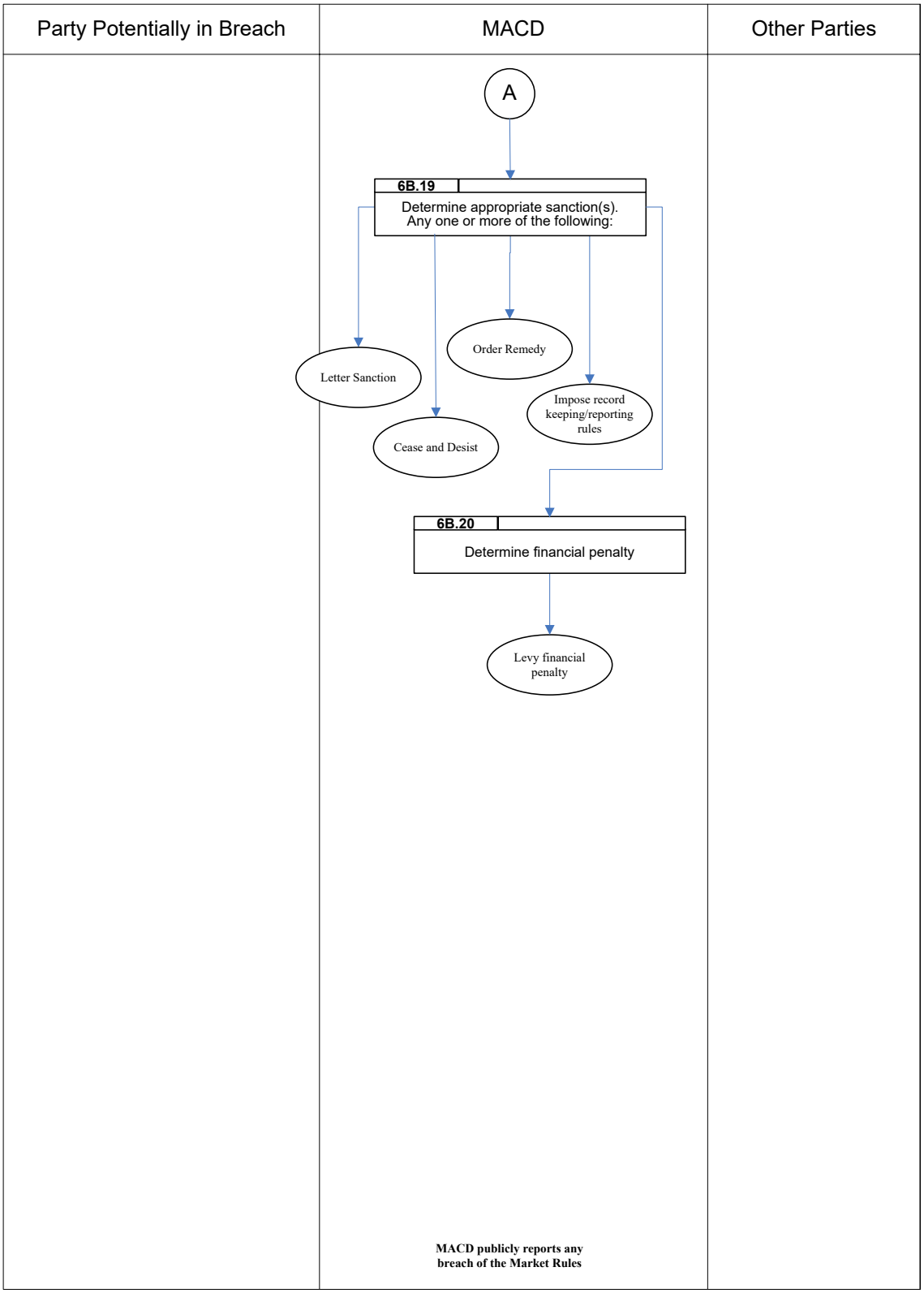


Figure 2–2.2: Work Flow for the Treatment of Alleged Breach of the Market Rules – Formal Process (continued)

2.3 Suspension of a Market Participant

In the event that a *market participant* has been determined to have persistently breached the *market rules*, does not remedy an *event of default* within the specified period or a specified *event of default* occurs, the *IESO* is authorized to issue a *suspension order* suspending the *market participant's* rights to participate in the *IESO-administered markets* or cause or permit electricity to be conveyed into, through, or out of the *IESO-controlled grid*.

In the event of persistent breaches of the *market rules*, prior to the issuance of a s*uspension order,* the *IESO* must notify the defaulting *market participant* of its intent to issue such order and the grounds for its issuance. The *market participant* will be given an opportunity to make a case to the *IESO Board* as to why they should not be issued a s*uspension order*.

If a *suspension order* is issued, a *disconnection order* may also be issued to the *transmitter(s)*, *distributor(s)* or other *market participant* to whose *facilities* the *suspended market participant* is *connected* with a copy provided to the *OEB*. If a *disconnection order* has been issued to the relevant *transmitter(s)*, *distributor(s)* or other *market participant*, a notification will be included in the *suspension order* to the *market participant*.

Where a m*arket participant* is suspended, they are given a period of time to remedy the cause of the suspension, after which the *IESO* may start the process of terminating the *market participant* (see Section 2.4)

The steps shown in Figure 2–3 are described in detail in Section 3.3, Table 3–3.

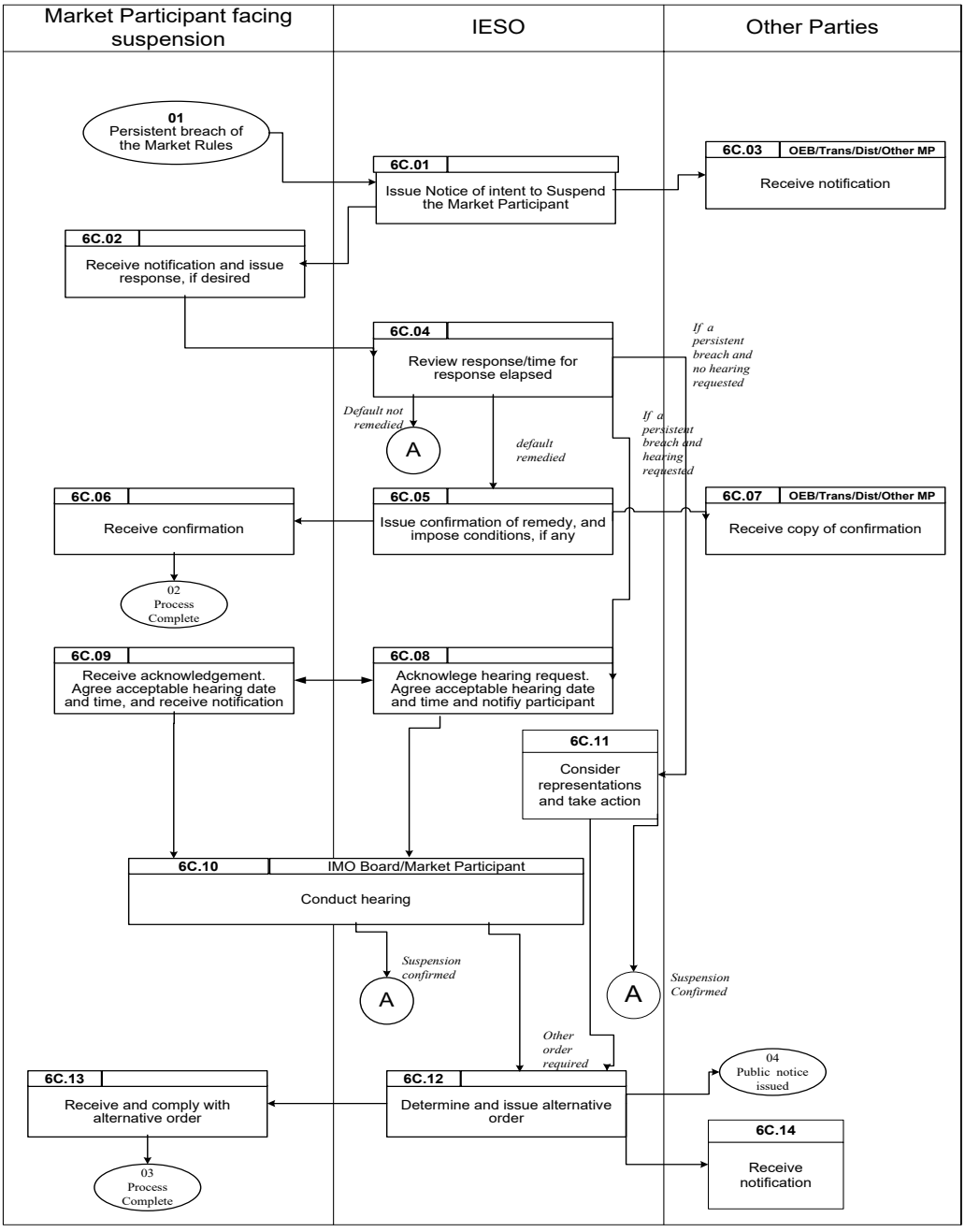


Figure 2–3: Work Flow for the Suspension of a Market Participant

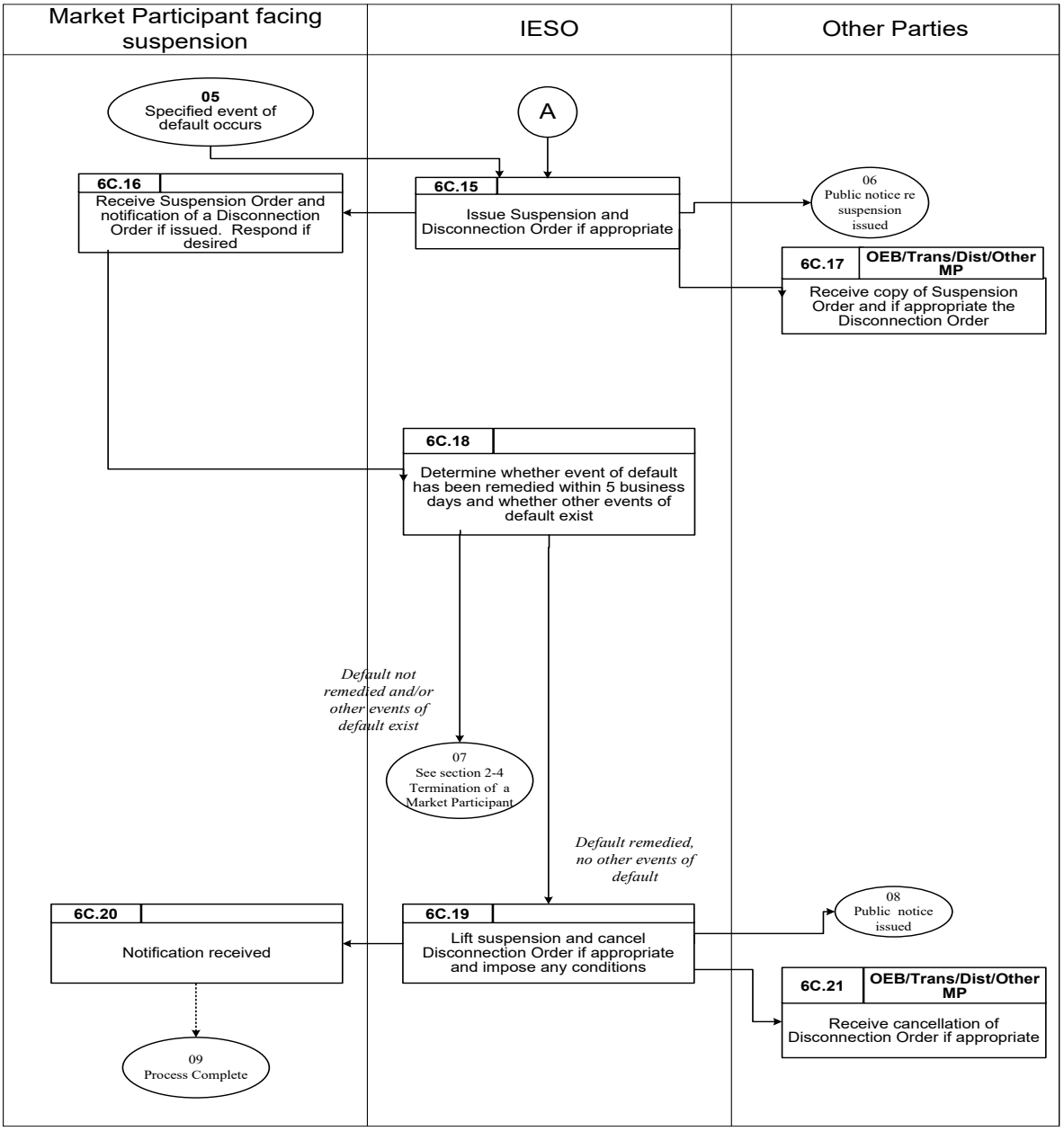


Figure 2–3: Work Flow for the Suspension of a Market Participant **(continued)**

2.4 Termination of a Market Participant

Where a *suspended market participant* has either not remedied an *event of default* within the specified time period or notified the *IESO* that it is not likely to remedy the *event of default*, or where a *market participant* has been wound up, dissolved or otherwise ceased to exist, or where a *market participant* has been determined to be in persistent breach of the *market rules,* the *IESO* may:

- Issue a *termination order* terminating the *market participant's* rights to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through, or out of *the IESO controlled grid*; and
- if it has not already done so, issue a *disconnection order* .to the *transmitter, distributor* and/or other *market participant* to whose *facilities* the *terminated market participant's facilities* are connected and provide a copy to the *OEB*.

The steps shown in Figure 2–4 are described in detail in Section 3.4, Table 3–4.

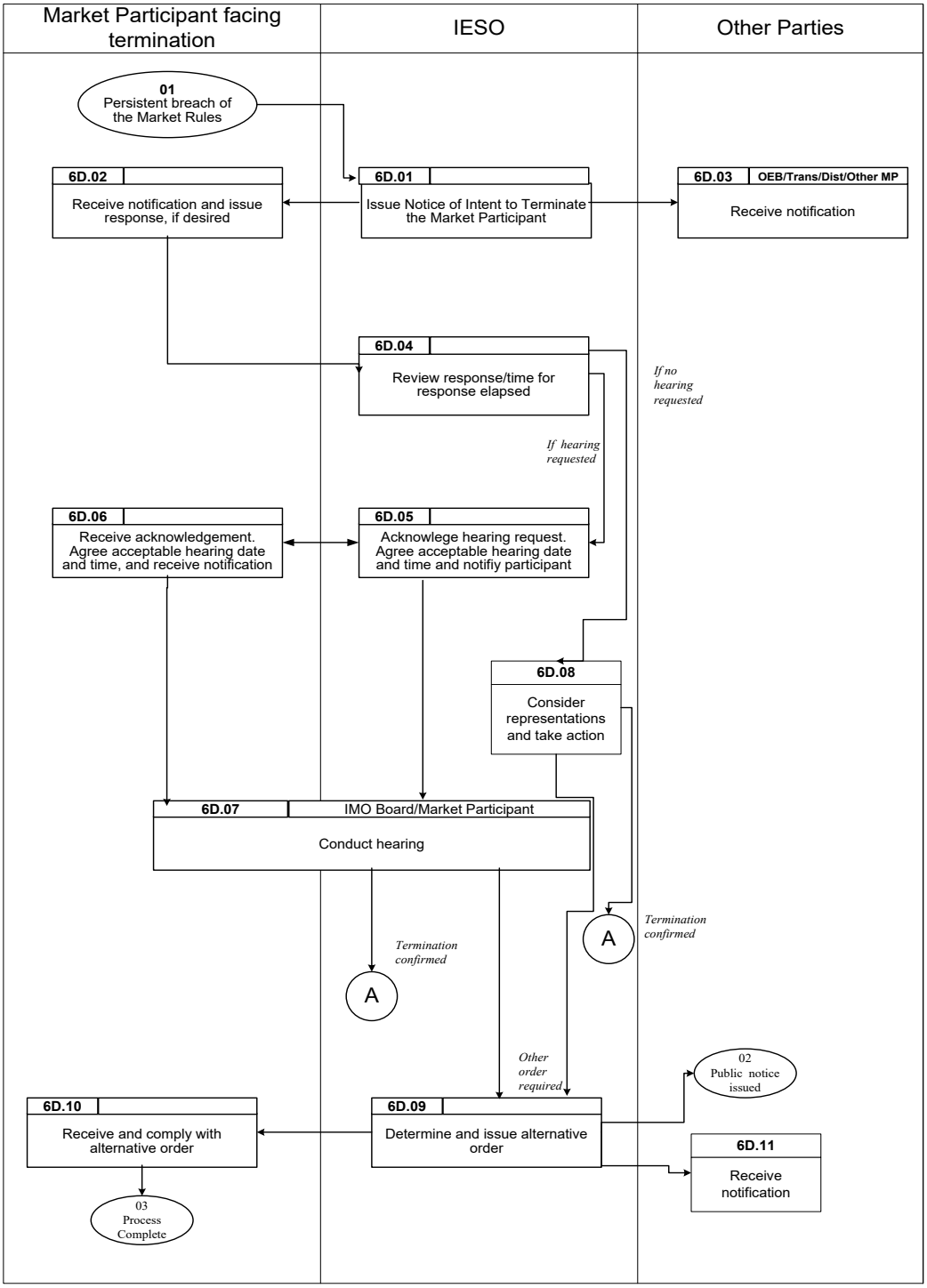


Figure 2–4: Work Flow for the Termination of a Market Participant

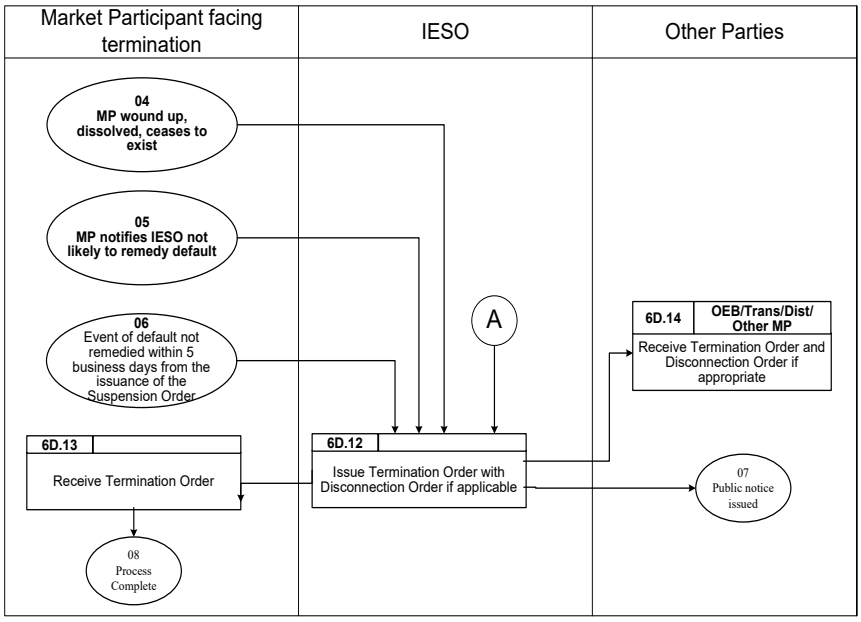


Figure 2–4: Work Flow for the Termination of a Market Participant (continued)

2.5 De-registration of Facilities

Where a *market participant* has been determined to have persistently breached the *market rules,* the *IESO* may:

- de-register some or all of the *market participant's registered facilities*; and
- issue a *disconnection order* .to the *transmitter, distributor* and/or other *market participant* to whose *facilities* the *terminated market participant's facilities* are connected and provide a copy to the *OEB*.

The steps shown in Figure 2–5 are described in detail in Section 3.5, Table 3–5.

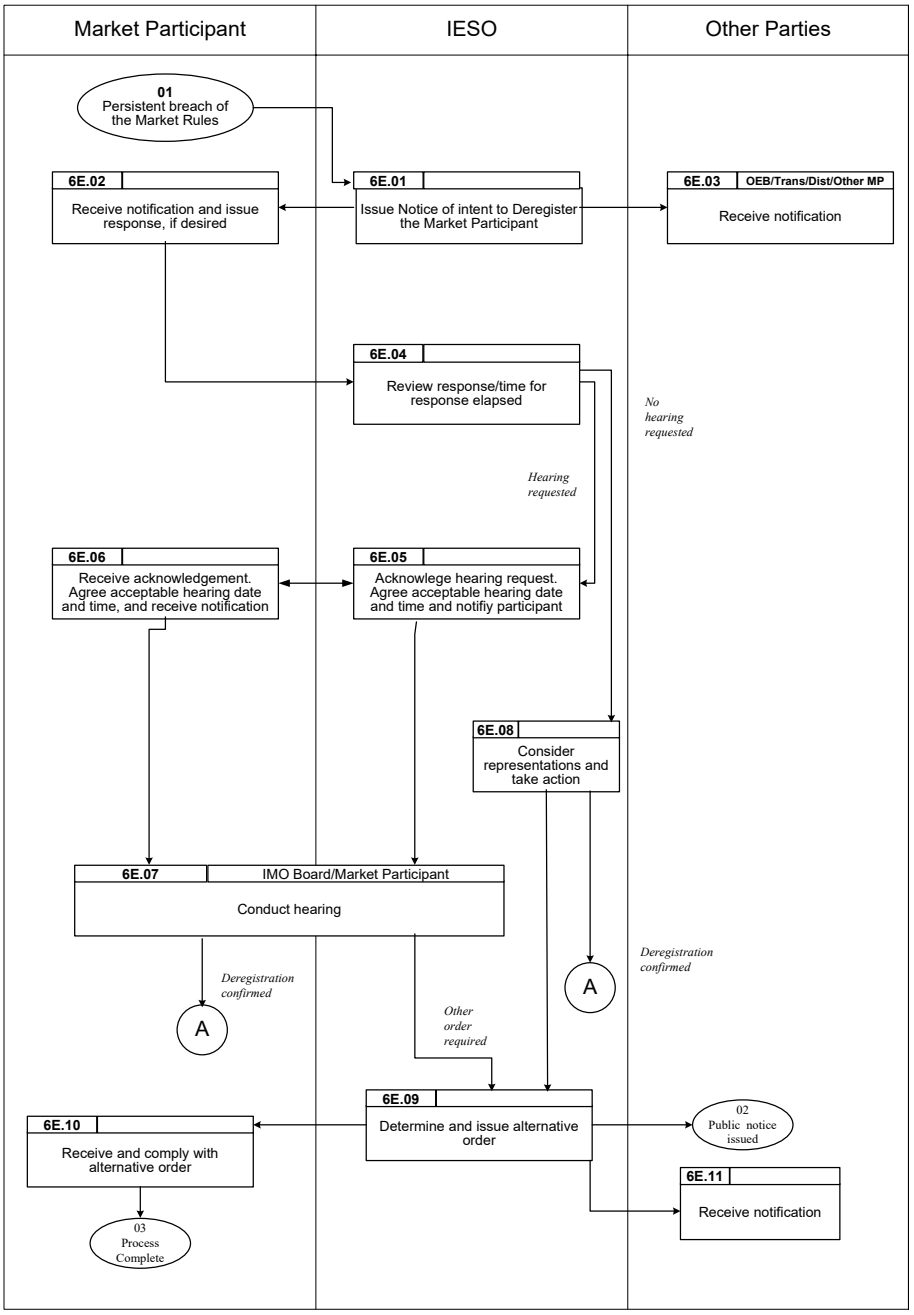


Figure 2–5: Work Flow for the De-registration of Facilities

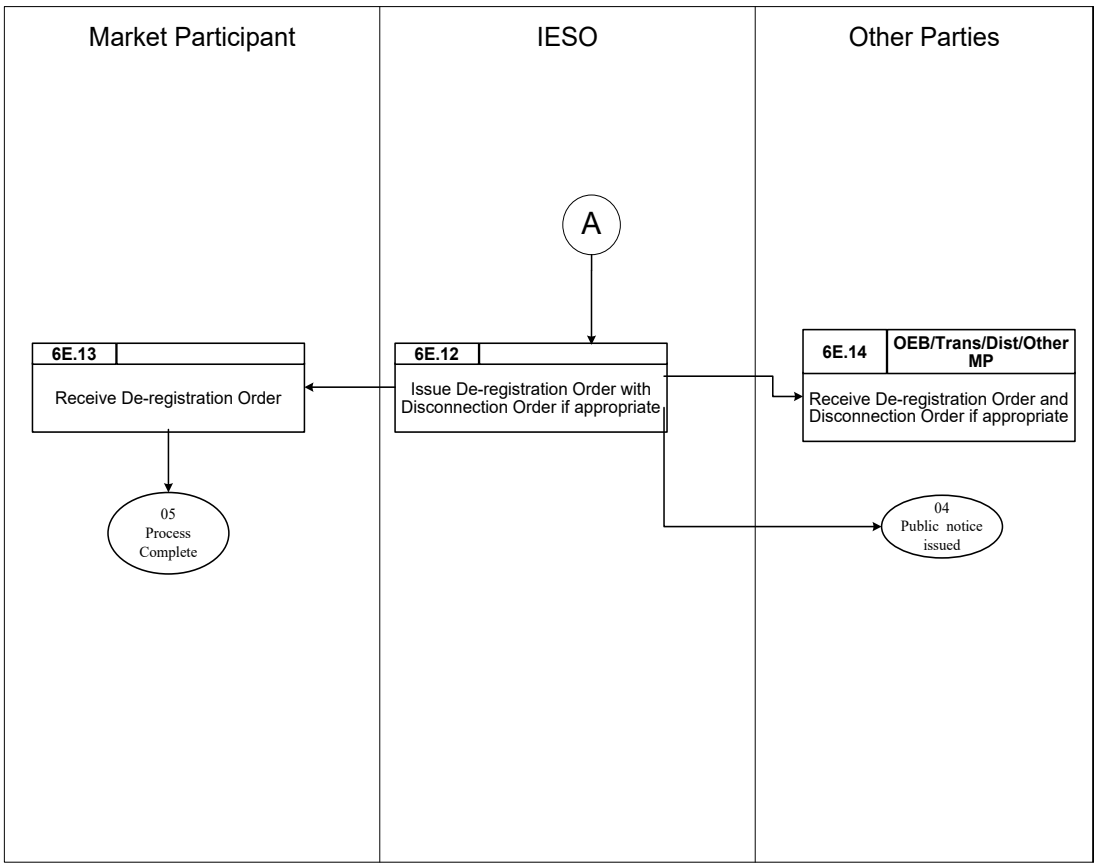


Figure 2–5: Work Flow for the De-registration of Facilities (continued)

– End of Section –

3. Procedural Steps

This section contains detail on the tasks (steps) that comprise the treatment of compliance issues. The tables contain seven columns, as follows:

Ref

The numerical reference to the task.

Task Name

The task name as identified in Section 2.

Task Detail

Detail about the task.

When

A list of all the events that can trigger commencement of the task.

Resulting Information

A list of the information flows that may or must result from the task.

Method

The format and method for each information flow are specified.

Completion Events

A list of all the circumstances in which the task should be deemed finished.

3.1 Identification of Compliance Issues

When a non-compliance event has been identified, MACD notifies the party potentially in breach and requests that the behaviour causing the non-compliance be corrected. MACD will then determine the type of non-compliance event that has been identified prior to taking the appropriate procedural steps shown in Table 3-1 are illustrated in Section 2.1, Figure 2–1.

Table 3–1: Procedural Steps for Identification of Compliance Issues

Ref	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
6A.01	Self-report non-compliant event to MACD	A *market participant* or the *IESO* may report an event of non-compliance to MACD for the following reasons: • a *market participant* that is in non-compliance may voluntarily report themselves to the *IESO*. Voluntary self-reporting may act to mitigate a sanction that might be imposed if the non-compliance was discovered by the *IESO*, or as the result of information obtained from another source; • the *market rules* require the *market participant* to report to the *IESO* certain events that constitute or may give rise to an *event of default* (Chapter 3, subsection 6.3.2 of the *market rules*).	Upon discovery of non-compliant behaviour	Notification of non-compliance in the form of the *"*Non-Compliance Event Report*"* – IMO- FORM- 1253 or a document containing the same information	Fax or email	Non-compliance event reported to MACD
6A.02	Report non-compliant event to MACD	A third party (including the *IESO*) may discover evidence of non-compliant behaviour and notify MACD.	Upon discovery of non-compliant behaviour	Notification of non-compliance in the form of the *"*Non-Compliance Event Report*"* – IMO-FORM-1253 or a document containing the same information.	Fax or email	Non-compliance event reported to MACD

6A.03	Receive report	When MACD has been notified of a non-compliant event, it will contact and notify the party potentially in breach and request that the behaviour leading to their alleged breach be corrected.	Upon notification from a *market participant, IESO* or other third party of a compliance issue	Notification of compliance issue and request for correction of behaviour.	Telephone and/or email	Information on potential non-compliance issue is received and logged. MACD acknowledges receipt of report. MACD may request *market participant* to correct behaviour.
6A.04 6A.05	Receive confirmation	Reporting party receives confirmation of receipt of report of non-compliance.	Upon receipt of report by MACD	Confirmation of receipt.	Email	Acknowledgement received.
6A.06	Determine type of compliance issue	MACD examines the available information to determine the type of compliance issue. MACD will determine that either: • a potential breach of the *market rules* has occurred; • an *event of default* has occurred in relation to *prudential support* (see "Market Manual 5: Settlements, Part 5.4 Prudential Support"; • an *event of default* has occurred in relation to payment (see "Market Manual 5: Settlements, Part 5.9 Payment Methods & Schedule"); • an *event of default* has occurred that cannot be remedied under the *market rules*, leading to suspension (see Section 2.3); or	Following step 6A.05	None	None	The type of compliance issue determined. Where MACD determines that a compliance issue cannot be identified, the *IESO* may still decide that an action of a *market participant* may be of concern to the *Market Assessment Unit* (see "Market Manual 2: Part 2.7: Treatment of Market Surveillance Issues").

		• that a compliance event has not occurred. A list of *events of default* is set out in Appendix B.				
6A.07	Screening criteria assessment	MACD assesses the compliance issue to determine how to proceed with the investigation.	After MACD has determined whether a potential breach of the *market rules* has occurred	None	None	MACD will determine to either: • notify the party that no further action will be taken; • commence an informal investigation; • commence a formal investigation; or • in the event a third party or self-report has been received and no further action will be taken, the reporting party will be notified.

3.2 Treatment of Alleged Breach of the Market Rules

Where the *IESO* determines that a compliance issue is an alleged breach of the *market rules*, it will conduct an investigation to confirm (or otherwise) the breach. As part of this investigation, MACD will seek information from the non-compliant *market participant* and the party reporting the compliance issue and, on request, meet with the *market participant* to review the evidence presented. Where a breach is confirmed, the *IESO* will apply the appropriate sanction to the *market participant*. Steps shown in Table 3.2 are illustrated in Section 2.2, Figure 2–2.1 and 2-2.2.

Table 3–2: Procedural Steps for Treatment of Alleged Breach of the Market Rules

Ref	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
6B.01	Issue request for information	MACD sends a description of the compliance event and requests additional information.	At the start of an informal investigation	None	Email	Request for additional information issued to the *market participant* and/or other party
6B.02 6B.03	Receive request and provide additional information	The party potentially in breach or other party receives the request from MACD and provides the additional information requested.	Following step 6B.01	Information specified in "Request for Information".	Email or fax	Request received by the party potentially in breach or other party and additional information submitted to MACD
6B.04	Review *response*	MACD reviews all of the information available and • determines that there was no breach of the *market rules* and issuing an informal or formal notice is not appropriate, MACD will notify the party potentially in breach that no further action will be taken; • determines that the party may have breached a *market rule* and if the breach is established a sanction would be appropriate and a formal investigation is initiated; or • determines that there was a technical breach of a *market rule* but a sanction is not appropriate and a *market rule reminder* is issued.	Upon receipt of additional information	None	Email Email	Process to proceed is determined "Close Out Notice" sent "Market Rule Reminder" sent

Ref	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
6B.05	Issue "Notice of Alleged Breach with condition(s)	MACD issues "Notice of Alleged Breach with conditions. "Notice of Alleged Breach" will identify: • details of the alleged breach; • the time in which the breach must be remedied; • details of the evidence on which the MACD reached its determination; • details of potential sanctions that may be imposed if the conditions set out are not met by the time specified.	MACD assess the breach as inconsequential but requires remedy	None	Email	Notification sent to party allegedly in breach
6B.06	Receive "Notice of Alleged Breach with condition(s)	Party potentially in breach receives "Notice of Alleged Breach" with condition(s)	Following step 6B.05	None	None	Receipt of notice
6B.07 6B.08	Notify MACD conditions met	Party potentially in breach has met/complied with conditions in "Notice of Alleged Breach" and notifies MACD.	Once conditions have been met	Notice that conditions have been met.	Email	"Close Out Notice" sent
6B.09	Issue "Notice of Alleged Breach" of *market rules*	MACD issues a notification of an alleged breach to the party potentially in breach, identifying: • details of the alleged breach; • the time in which the breach must be remedied; • details of the evidence on which the MACD reached its determination;	Upon determination by MACD that the party may have breached a *market rule* and if a breach is established, a sanction is appropriate	"Notice of Alleged Breach" of *market rule*s	Email	"Notice of Alleged Breach" issued

Ref	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
		• details of potential sanctions that may be imposed if the breach is established (in line with the sanctions set out in Chapter 3, section 6.6 and Appendix 3.1 of the *market rules)*; • the time within which the party potentially in breach may submit a written *response* to the notification; and • the rights of the party potentially in breach to request a meeting with the MACD to discuss the alleged breach.				
6B.10	Receive notification and issue *response*, if desired (including a request for a meeting)	The party potentially in breach receives the notification of the alleged breach and may issue a *response*, if desired, outlining whether it agrees that a breach has occurred, how it will remedy the alleged breach, where it agrees that a breach has occurred, or other *response* that it deems appropriate. The *response* may include a request to meet with the *IESO* to discuss the alleged breach.	Following Step 6B.09, within the timeframe set out in the "Notice of Alleged Breach" of *market rules*	*Response* to "Notice of Alleged Breach" of *market rules*	Email	*Response* sent to the MACD
6B.11	Review *response* and schedule meeting, if requested by party	MACD reviews any *response* from the party potentially in breach.	Following Step 6B.10, if a meeting has been requested	Acknowledgement of Meeting Request	Email	Notice of meeting sent to party potentially in breach

Ref	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
	potentially in breach	If a meeting has been requested, an acknowledgement is sent. A mutually acceptable date and venue for a meeting is scheduled and the party potentially in breach is notified of the date, time and venue for the meeting.				
6B.12	Receive notification of meeting	The party potentially in breach receives notification of the meeting to examine the alleged breach.	Following step 6B.11	None	None	Notification of meeting received by party potentially in breach
6B.13	Hold meeting with party potentially in breach to examine alleged breach	Meeting held between the *IESO* and party potentially in breach to discuss the alleged breach. Formal meeting minutes may be issued to all *participant*s to ensure proper representation of all parties and these minutes may form part of the input to the investigation undertaken in step 6B.06.	Following step 6B.12 and as specified in the notification of the meeting	Minutes of meeting	Email	Meeting completed
6B.14	Conduct investigation and request additional information as necessary	MACD initiates an investigation into the alleged breach based on the information necessary to reach a decision regarding the alleged breach. If additional information is needed, a request is issued to the party potentially in breach for the information.	Following the expiry of the time for *response*s set out in the notification submitted in step 6B.09 or	"Request for Information"	Email	Investigation completed

Ref	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
		The findings of the investigation are documented in the investigation report.	Following step 6B.13 if a meeting was requested			
6B.15 6B.16	Receive request for additional information and provide requested information	The party potentially in breach provides additional information requested by the MACD.	Following request made as part of step 6B.14	Information specified in "Request for Information".	Email, or telephone with hard copy follow-up by mail.	Information provided; meeting *attended*, if requested; meeting minutes received
6B.17	Determine whether a breach has occurred	Using the available information, the MACD determines whether a breach has occurred.	Following step 6B.16	None	None	Determination of whether a breach has occurred
6B.18	Determine appropriate action	If a sanction is not appropriate, • issue a "Conditional Close Notice"; or • issue a "Close Out Notice".	Following step 6B.17	None	Email	Receipt of notice by party potentially in breach
6B.19	Determine appropriate sanction	MACD may order that the party in breach to: • do, within a specified period, such things as may be necessary to comply with the *market rules*; • cease, within a specified period, the act, activity or practice constituting the breach; • impose additional or more stringent record-keeping or reporting requirements on the party in breach;	Following step 6B.18	"Notice of Non-Compliance"		Party in breach notified of sanction

Ref	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
		• issue a non-compliance letter in accordance with Chapter 3, section 6.6 of the *market rule*s;				
		• impose financial penalties in accordance with Chapter 3, section 6.6 of the *market rule*s; and/or • take such other action as may be provided for in Appendix 3.1 of the *market rules* in respect of the *market rules* that has been breached.				
6B.20	Determine amount of financial penalty under 6.6.6	MACD determines whether the party in breach acted with due diligence and applies the appropriate financial penalty for the breach identified where due diligence is not in evidence. The amount of the financial penalty will be determined based on criteria set out in Chapter 3, section 6.6 of the *market rules*.	When a financial penalty is appropriate	Amount of penalty	Email Market Participant Interface (MPI)	Party in breach has been notified of the amount of the penalty in the "Notice of Non-Compliance". Where a financial penalty is applied, the *IESO* will issue a manual *invoice* for this penalty in accordance with the invoicing process set out in "Market Manual 5: Settlements, Part 5.6 *Physical Markets* Invoicing" or "Part 5.8 Financial Markets Invoicing", as appropriate.

Ref	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
6B.21	Determine amount of financial penalty under 6.6.6A	MACD determines whether the party in breach acted with due diligence and applies the appropriate financial penalty for the breach identified where due diligence is not in evidence. If a financial penalty is deemed appropriate under section 6.6.6A, the principles and methods in Appendix E will be used to determine the penalty amount. A draft notice of non-compliance is issued to the party allegedly in breach where they are provided with the preliminary penalty assessment and an opportunity to submitted additional information or comment.	When a financial penalty is appropriate Follow step 6B.21	Amount of penalty	Email	Party in allegedly breach has been notified of the amount of the penalty in the “Draft Notice of Non-Compliance”.

3.3 Suspension of a Market Participant

In the event that a *market participant* has been determined to have breached the *market rules* on a persistent basis, does not remedy an *event of default* within the time specified in the *notice of intent to suspend*, or a specified *event of default* occurs, the *IESO* is authorized to issue a *suspension order* suspending the *market participant's* rights to participate in the *IESO-administered markets* or cause or permit electricity to be conveyed into, through, or out of the *IESO-controlled grid*.

A *disconnection order* may also be issued at the same time the *suspension order* is issued to the *transmitter, distributor,* or other *market participant* to whose *facilities* the *market participant* is *connected*. If a *disconnection order* has been issued, a notification will be included in the *suspension order* to the *market participant*.

Prior to issuing the *suspension order* as a result of a persistent breach of the *market rules,* the *IESO* will notify the *market participant* of its intent to issue such an order. The *market participant* is given the opportunity to make a case before the *IESO Board* as to why the *suspension order* should not be issued.

Where a *market participant* is suspended, it is given a period of time to remedy the cause of the suspension, after which the *IESO* may start the process of terminating the *market participant*.

Steps shown in Table 3.3 are illustrated in Section 2.3, Figure 2–3.

Table 3–3: Procedural Steps for Suspension of a Market Participant

Ref	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
6C.01	Issue "*Notice of Intent to Suspend*" to *market participant*.	Where a *market participant* has persistently breached the *market rules* or an *event of default* occurs, the *IESO* may issue to the *market participant* a "*Notice of Intent to Suspend*". Such notice would inform the *market participant* of the *IESO's* intention to issue a s*uspension order* suspending all or any of the *market participant's* rights to participate in the *IESO administered markets*. In the case of a persistent breach, this notice would also indicate the right of the *market participant* to request within a specified time a hearing before the *IESO Board* to show cause why the suspension *order* should not be issued.	At the discretion of the *IESO* if an *event of default* occurs or if a *market participant* has persistently breached the *market rules*.	"*Notice of Intent to Suspend*" (IMO FORM 1260)	Courier	"*Notice of Intent to Suspend"* is issued to the *market participant*.

6C.02	Receive notification and issue *response*, if desired.	The *market participant* receives the notification of intended suspension and, if desired, may issue a *response*.	Following Step 6C.01, and within 2 *business days* (in the case of an *event of default*), or within a specified time (in the case of a persistent breach) if a hearing is requested. A hearing is only available to the *market participant* where action is a result of a persistent breach of the *market rules*.	*Response* to "Notice of Intent to Suspend" "Notice of Hearing with Board of Directors" (IMO FORM 1265) (only for persistent breached of the *market rules)*	Email with follow up hard copy via Canada Post if requested.	Notification received by the *market participant*; letter of *response* issued to the *IESO*, if desired.
6C.03	Receive notification.	In the case of a persistent breach, a copy of the "*Notice of Intent to Suspend"* will be sent to the *OEB* and the *transmitter, distributor* and/or other *market participant* to whose *facilities* the *market participant's facilities* are *connected*.	When the "Notice of Intent to Suspend" is issued.	None	None	"*Notice of Intent to Suspend*" is issued to the *OEB* and the *transmitter, distributor* and/or other *market participant* to whose *facilities* the *market participant's facilities are connected*.

6C.04	Review response/time for response elapsed.	The *IESO* reviews the response to determine if: • the *market participant* has remedied the *event of default* within the required time frame. • the *market participant* requests a hearing before the *IESO Board* to make a case as to why the order or orders should not be issued (only for persistent breaches of the *market rules)*; or, • the *market participant* does not respond.	Following Step 6C.01.	None	None	Response, if any, received by the *IESO*.
6C.05	Issue confirmation of remedy and impose conditions, if any.	The *IESO* confirms with the *market participant* their remedy of the *event of default* condition that triggered the "*Notice of Intent to Suspend*." The *IESO* may also impose any condition on the right of the *market participant* to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, though, or ot of the *IESO-controlled* grid that the *IESO* determines are appropriate	Upon receipt from a *market participant* indicating that the *event of default* which triggered the "*Notice of Intent to Suspend*", has been remedied.	Confirmation of remedy	Courier	Remedy of event of default confirmed by the *IESO*.
6C.06	Receive confirmation.	The *market participant* facing suspension receives *IESO* confirmation of its remedy.	Following Step 6C.05.	None	None	Remedy of *event of default* confirmed with the *market participant*.

6C.07	Receive copy of confirmation.	The *OEB* and relevant *transmitter*(s), *distributor*(s) or other *market participant* also receive a copy of the confirmation.	Following Step 6C.05.	None	None	Remedy of *event of default* confirmed with the *OEB* and relevant *transmitter*(*s*) or *distributor*(*s*)
6C.08	Acknowledge hearing request. Agree acceptable hearing date and time and notify *market participant*.	The *IESO* acknowledges the hearing request and schedules a mutually acceptable date and venue for a hearing, if requested by the *market participant*. Once a date has been decided, the *IESO* formally notifies the *market participant* of the date, time and location of the hearing and provides details of how the hearing will be conducted.	Upon request for a hearing.	Acknowledgement "Notice of Hearing with Board of Directors" (IMO FORM 1265).	Email or fax	Hearing request acknowledged. Date, time and location of hearing determined. Formal notification issued.
6C.09	Receive acknowledgement. Agree on acceptable hearing date and time and receive notification.	The *market participant* receives acknowledgment that the *IESO* has reviewed their hearing request. The *market participant* and the *IESO* schedule a mutually acceptable date and venue for a hearing. Once a date has been decided, the *market participant* receives from the *IESO*, formal notification about the details of the hearing.	*IESO* acknowledges hearing request.	Agree on date and time of hearing.	Email or fax	*IESO* acknowledgement of hearing request received. Date, time and location of hearing agreed. Receipt of formal notification.
6C.10	Conduct hearing	The *IESO Board* conducts the hearing and determines whether a s*uspension order* is appropriate or an alternative order should be made.	Following Step 6C.09	Minutes of hearing.	Email, mail or fax	Determination that s*uspension order* should be issued or alternative order issued.

6C.11	Consider representations and take action	If the *market participant* does not request a hearing, the IESO shall consider any written representations received from the *market participant*, and may take any action specified in the Notice of Intent to Suspend or make any appropriate order.	Following 6C.04	Determination of action or order if applicable.	None	Determination of action or order if applicable.
6C.12	Determine and issue alternative order.	The *IESO* issues an alternative order to the *market participant*. Amongst possible orders, the *IESO* may order that the *market participant;* • do, within a specified period, such things as may be necessary to comply with the *market rules*; • cease, within a specified period, the act, activity or practice constituting the breach; • impose additional or more stringent record-keeping or reporting requirements on the *market participant*; • issue a non-compliance letter in accordance with Chapter 3, section 6.6 of of the *market rule*s; • impose financial penalties in accordance with Chapter 3, section 6.6 of the *market rule*s.	Upon determination in Step 6C.10 that a s*uspension order* is not appropriate.	"Other Order" (IMO-FORM-1268) Public notification of other order	Email followed up with hard-copy via courier. *IESO* public Web site	Letter issued to the *market participant.*

6C.13	Receive and comply with alternative order.	The *market participant* receives the alternative order with which it must comply.	Following Step 6C.12.	None	None	Process completed.
6C.14	Receive notification	A notice of any actions taken under section 6.2A.4 or 6.2A.5 will be sent to the *OEB* and the *transmitter, distributor* and/or other *market participant* to whose *facilities* the *market participant's facilities* are *connected*.	Following 6C.12.	None	None	Notice of any actions taken is issued to the *OEB* and the *transmitter, distributor* and/or other *market participant* to whose *facilities* the *market participant's facilities* are connected.

6C.15	Issue S*uspension* and *Disconnection Order* if appropriate.	The *IESO* issues *a suspension order* to the *market participant* containing the following information; • the reasoning and evidence behind the *suspension order*; • details on the specific market rights being suspended; • the duration of the suspension; • the actions required in order for the *suspension order* to be lifted; and • notification if the relevant *transmitter(s)* or *distributor(s)* have been issued a *disconnection order* The *IESO* may also issue a *disconnection order* to the *transmitter(s)*, *distributor(s)* or other *market participant* to whose *facilities* the *market participant's facilities* are *connected*.	Following Step 6C.04 if the *event of default* is not remedied by the *market participant*. Following Step 6C.10 or 6C.11 if it is determined that the *suspension order* is appropriate. Following a specified *event of default*.	"*Suspension Order*" (IMO-FORM-1261) "*Disconnection Order*" (IMO-FORM-1302) Public notification of Orders.	Email, courier or *IESO* public Web site.	*Market participant* suspended.

6C.16	Receive *suspension order* and notification of *disconnection order* if issued. Respond if desired.	• The *market participant* receives the *suspension order* and notification if a *disconnection order* has been issued. The *market participant* has five *business days* to respond to the *suspension order* by remedying the *event of default* before the *IESO* may issue a termination order.	Following Step 6C.15.	*Response* to *suspension order* and *disconnection order* if applicable.	Email or courier	Receipt of *suspension order* and notice of *disconnection order* if issued. Response if desired.
6C.17	Receive copy of *suspension order* and *disconnection order* if issued.	The *IESO* shall provide a copy of the *suspension order*, and the disconnection order, if issued, to the OEB and the *transmitter*, *distributor* and/or other *market participant* to whose *facilities* the *suspended market participant* is connected.	Following Step 6C.15.	None	None	Receipt of *suspensionorder* and *disconnection order* if appropriate.
6C.18	Determine whether *event of default* has been remedied within 5 *business days* and whether other *events of default* exist.	The *IESO* determines whether the *event of default* has been remedied and whether any other *events of default* exist.	Five *business days* following Step 6C.15 or if no *response* received within timeframe.	None	None	Determination of whether *event of default*is remedied and whether other *events of default* exist.

6C.19	Lift *suspension order* and cancel *disconnection order* if appropriate; impose any further conditions.	The *IESO* notifies the *market participant* and public of the resolution to the compliance issue and the lifting of the suspension, including: • the rights to be reinstated; and • the date on which the *suspension order* is terminated. In addition, as a condition of lifting the *suspension order* the *IESO* may impose additional conditions of authorization on the *market participant* as it determines are necessary. These may include (but are not limited to): • lowering the *trading limit* of the *market participant*; • establishing a more frequent continuing schedule of payments than are set out in the *Settlement Statement* Payment Calendar; and/or • imposing a more stringent *prudential support obligation* than would otherwise be the case under Chapter 2, section 5 of the *market rules*.	Upon determination in Step 6C.18 that the issue has been resolved.	"Lift of *Suspension Order*" (IMO-FORM-1263) "Canceling "*Disconnection Order*"" (TBD)	E-mail followed up with hard-copy via courier. *IESO* public Web site.	Letter issued to the *market participant.* Public notification through *IESO* Web site.
6C.20	Notification received.	The *market participant* is notified of the resolution, including any additional conditions of authorization.	Following Step 6C.19.	None	None	Letter issued to the *market participant*. Public notification through *IESO* Web site.

6C.21	Receive cancellation of *disconnection order* if appropriate.	The *IESO* shall provide a copy of the cancellation of the *disconnection order* if appropriate to the OEB and the *transmitter*, *distributor* and/or other *market participant* to whose *facilities* the *market participant* is connected.	Following Step 6C.19.	None	None	Cancelation of *Disconnection Order* received.

3.4 Termination of a Market Participant

Where a *suspended market participant* has either not remedied an *event of default* within the specified time period or notified the *IESO* that it is not likely to remedy the *event of default*, or where a *market participant* has been wound up, dissolved or otherwise ceased to exist, or where a *market participant* has been determined to be in persistent breach of the *market rules,* the *IESO* may;

- Issue a *termination order* terminating the *market participant's* rights to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through, or out of the *IESO-controlled grid*; and
- if it has not already done so, issue a *disconnection order* to the *transmitter, distributor* and/or other *market participant* to whose *facilities* the *terminated market participant's facilities* are connected and provide a copy to the *OEB.*

The steps shown in the following table are illustrated in Section 2.4, Figure 3–4.

Table 3–4: Procedural Steps for Termination of a Market Participant

Ref	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
6D.01	Issue "*Notice of Intent to Terminate*" to *market participant*.	Where a *market participant* has persistently breached the *market rules*, the *IESO* may issue to the *market participant* a "*Notice of Intent to Terminate*". Such notice would inform the *market participant* of the *IESO's* intention to issue a *termination order* terminating all or any of the *market participant's* rights to participate in the *IESO administered markets*. In the case of a persistent breach, this notice would also indicate the right of the *market participant* to request within a specified time a hearing before the *IESO Board* to show cause why the termination *order* should not be issued.	At the discretion of the *IESO* if a *market participant* has persistently breached the *market rules*.	"*Notice of Intent to Terminate*" (IMO FORM 1266)	Courier	"*Notice of Intent to Terminate"* is issued to the *market participant*.
6D.02	Receive notification and issue *response*, if desired.	The *market participant* receives the notification of intended termination and, if desired, may issue a response.	Following Step 6D.01, and within a specified time if a hearing is requested. A hearing is only available to the *market participant*	*Response* to "Notice of Intent to Terminate" "Notice of Hearing with Board of Directors" (IMO FORM 1265)	Email with follow up hard copy via Canada Post if requested.	Notification received by the *market participant*; letter of response issued to the *IESO*, if desired.

Ref	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
			where action is a result of a persistent breach of the *market rules*.			
6D.03	Receive notification.	In the case of a persistent breach, a copy of the "*Notice of Intent to Terminate"* will be sent to the *OEB* and the *transmitter, distributor* and/or other *market participant* to whose *facilities* the suspended *market participant's facilities* are *connected*.	When the "Notice of Intent to Terminate" is issued.	None	None	"*Notice of Intent to Terminate*" is issued to the *OEB* and the *transmitter, distributor* and/or other *market participant* to whose *facilities* the suspended *market participant's facilities are connected*.
6D.04	Review response/time for response elapsed.	The *IESO* reviews the *response* to determine if: • the *market participant* requests a hearing before the *IESO Board* to make a case as to why the order or orders should not be issued; or, • the *market participant* does not respond.	Following Step 6D.01.	None	None	Response received by the *IESO*.
6D.05	Acknowledge hearing request. Agree acceptable hearing date and time and notify *market participant*.	The *IESO* acknowledges the hearing request and schedules a mutually acceptable date and venue for a hearing, if requested by the *market participant*. Once a date has been decided, the *IESO* formally notifies the *market*	Upon request for a hearing	Acknowledgement "Notice of Hearing with Board of Directors" (IMO FORM 1265).	Email or fax	Hearing request acknowledged. Date, time and location of hearing determined. Formal notification issued.

Ref	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
		participant of the date, time and location of the hearing and provides details of how the hearing will be conducted.				
6D.06	Receive acknowledgement. Agree on acceptable hearing date and time and receive notification.	The *market participant* receives acknowledgment that the *IESO* has reviewed their hearing request. The *market participant* and the *IESO* schedule a mutually acceptable date and venue for a hearing. Once a date has been decided, the *market participant* receives from the *IESO*, formal notification about the details of the hearing.	*IESO* acknowledges hearing request.	Agree on date and time of hearing.	Email or fax	*IESO* acknowledgement of hearing request received. Date, time and location of hearing agreed. Receipt of formal notification.
6D.07	Conduct hearing	The *IESO Board* conducts the hearing and determines whether a *termination order* is appropriate or an alternative order should be made.	Following Step 6D.05	Minutes of hearing.	Email, mail or fax	Determination that *termination order* should stand or be modified.
6D.08	Consider representations and take action	If the *market participant* does not request a hearing, the *IESO* shall consider any written representations received from the *market participant*, and make take any action specified in the notice or make any appropriate order.	Following 6D.04	Determination of action or order if applicable.	None.	Determination of action or order if applicable.

Ref	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
6D.09	Determine and issue alternative order.	The *IESO* issues an alternative order to the *market participant*. Amongst possible orders, the *IESO* may order that the *market participant;* • do, within a specified period, such things as may be necessary to comply with the *market rules*; • cease, within a specified period, the act, activity or practice constituting the breach; • impose additional or more stringent record-keeping or reporting requirements on the *market participant*; • issue a non-compliance letter in accordance with Chapter 3, section 6.6 of of the *market rule*s; • impose financial penalties in accordance with Chapter 3, section 6.6 of the *market rule*s.	Upon determination in Step 6D.07 that a *termination order* is not appropriate.	"Other Order" (IMO-FORM-1268) Public notification of other order	Email followed up with hard-copy via courier. *IESO* public Web site	Letter issued to the *market participant.*
6D.10	Receive and comply with alternative order.	The *market participant* receives the alternative order with which it must comply.	Following Step 6D.09.	None	None	Process completed.
6D.11	Receive notification	A notice of any actions taken under section 6.2A.4 or 6.2A.5 will be sent to the *OEB* and the *transmitter, distributor*	Following 6D.09.	None	None	Notice of any actions taken is issued to the *OEB* and the *transmitter, distributor* and/or other

Ref	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
		and/or other *market participant* to whose *facilities* the *market participant's facilities* are *connected*.				*market participant* to whose *facilities* the *market participant's facilities are connected*.
6D.12	Issue *termination order* and *disconnection order* if appropriate.	The *IESO* issues a *termination order* to the *market participant,* detailing: • the evidence on which the *termination order* is based; • the effective date of termination; • the obligations of the terminated *market participant*; • process for reapplying for authorization as a *market participant* At the same time that a *termination order* is issued to the *market participant*, a *disconnection order* may be issued to the *transmitter*(*s*), *distributor*(*s*) or other *market participant* to whose *facilities* the *market participant* is *connected*.	Upon determination in Step 6D.07that a *termination order* is appropriate or within 20 *business days* from the date the *suspension order* was issued.	"*Termination Order*" (IMO-FORM-1267) "*Disconnection Order*" (IMO-FORM-1302) Public notification of Termination.	E-mail followed up with hard-copy via courier. *IESO* public Web site.	"Termination Order" issued and "Disconnection Order" issued if applicable
6D.13	Receive *termination order* and notification of *disconnection order* if issued.	The *market participant* receives the *termination order* and notification if a *disconnection order* has been issued.	Following Step 6D.12.	None	None	*Termination order* and *disconnection order*, if issued, received by the *market participant*.

Ref	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
6D.14	Receive *termination order* and *disconnection order* if issued.	The *IESO* shall provide a copy of the *termination order*, and the disconnection order if issued, to the *OEB* and the *transmitter(s)*, *distributor(s)* and/or other *market participant(s)* to whose *facilities* the *market participant* is connected. .	Following Step 6D.12.	None	None	Receipt of *termination order* and *disconnection order*, if issued.

3.5 De-registration of Facilities

Where a *market participant* has been determined to have persistently breached the *market rules,* the *IESO* may:

- de-register some or all of the *market participant's registered facilities*; and
- issue a *disconnection order* .to the *transmitter, distributor* and/or other *market participant* to whose *facilities* the *terminated market participant's facilities* are connected and provide a copy to the *OEB*.

The steps shown in the following table are illustrated in detail in Section 2.5, Figure 3–5.

Table 3–5: Procedural Steps for De-Registration of Facilities

Ref	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
6E.01	Issue "*Notice of Intent to De-register Facilities*" to *market participant*.	Where a *market participant* has persistently breached the *market rules*, the *IESO* may issue to the *market participant* a "*Notice of Intent to De-register Facilities*". Such notice would inform the *market participant* of the *IESO's* intention to issue a de-registration order de-registering some or all of *market participant's registered facilities.* This notice would also indicate the right of the *market participant* to request within a specified time a hearing before the *IESO Board* to show cause why the de-registration order should not be issued.	At the discretion of the *IESO* if a *market participant* has persistently breached the *market rules*.	"*Notice of Intent to De-register Facilities*" (IMO FORM 1301)	Courier	"*Notice of Intent to De-Register Facilities"* is issued to the *market participant*.
6E.02	Receive notification and issue *response*, if desired.	The *market participant* receives the notification of intended de-registration and, if desired, may issue a response.	Following Step 6E.01, and within a specified time if a hearing is requested. A hearing is only available to the *market participant* where action is a result of a persistent breach of the *market rules*.	Response to "Notice of Intent to De-register Facilities" "Notice of Hearing with Board of Directors" (IMO FORM 1265)	Email with follow up hard copy via Canada Post if requested.	Notification received by the *market participant*; letter of response issued to the *IESO*, if desired.

Ref	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
6E.03	Receive notification.	In the case of a persistent breach, a copy of the "*Notice of Intent to De-register Facilities"* will be sent to the *OEB* and the *transmitter, distributor* and/or other *market participant* to whose *facilities* the *market participant's facilities* are *connected*.	When the "Notice of Intent to De-register Facilities" is issued.	None	None	"*Notice of Intent to De-register Facilities*" is issued to the *OEB* and the *transmitter, distributor* and/or other *market participant* to whose *facilities* the *market participant's facilities are connected*.
6E.04	Review response/time for response elapsed.	The *IESO* reviews the *response* to determine if: • the *market participant* requests a hearing before the *IESO Board* to show cause why the order or orders should not be issued; or, • the *market participant* does not respond.	Following Step 6E.01.	None	None	Response received by the *IESO*.
6E.05	Acknowledge hearing request. Agree acceptable hearing date and time and notify *participant*.	The *IESO* acknowledges the hearing request and schedules a mutually acceptable date and venue for a hearing, if requested by the *market participant*. Once a date has been decided, the *IESO* formally notifies the *market participant* of the date, time and location of the hearing and provides details of how the hearing will be conducted.	Upon request for a hearing	Acknowledgement "Notice of Hearing with Board of Directors" (IMO FORM 1265).	Email or fax	Hearing request acknowledged. Date, time and location of hearing determined. Formal notification issued.

Ref	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
6E.06	Receive acknowledgement. Agree on acceptable hearing date and time and receive notification.	The *market participant* receives acknowledgment that the *IESO* has reviewed their hearing request. The *market participant* and the *IESO* schedule a mutually acceptable date and venue for a hearing. Once a date has been decided, the *market participant* receives from the *IESO*, formal notification about the details of the hearing.	*IESO* acknowledges hearing request.	Agree on date and time of hearing.	Email or fax	*IESO* acknowledgement of hearing request received. Date, time and location of hearing agreed. Receipt of formal notification.
6E.07	Conduct hearing	The *IESO Board* conducts the hearing and determines whether a de-registration order is appropriate or an alternative order should be made.	Following Step 6E.05	Minutes of hearing.	Email, mail or fax	Determination that de-registration order should stand or be modified.
6E.08	Consider representations and take action	If the *market participant* does not request a hearing, the *IESO* shall consider any written representations received from the *market participant*, and make take any action specified in the notice or make any appropriate order.	Following 6E.04	Determination of action or order if applicable.	None	Determination of action or order if applicable.
6E.09	Determine and issue alternative order.	The *IESO* issues an alternative order to the *market participant*. Amongst possible orders, the *IESO* may order that the *market participant;* • do, within a specified period, such things as may be necessary to comply with the *market rules*;	Upon determination in Step 6E.07 that a termination *order* is not appropriate.	"Other Order" (IMO-FORM-1268) Public notification of other order	Email followed up with hard-copy via courier. *IESO* public Web site	Letter issued to the *market participant.*

Ref	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
		• cease, within a specified period, the act, activity or practice constituting the breach; • impose additional or more stringent record-keeping or reporting requirements on the *market participant*; • issue a non-compliance letter in accordance with Chapter 3, section 6.6 of the *market rule*s; • impose financial penalties in accordance with Chapter 3, section 6.6 of the *market rule*s".				
6E.10	Receive and comply with alternative order.	The *market participant* receives the alternative order with which it must comply.	Following Step 6E.09.	None	None	Process completed.
6E.11	Receive notification	A notice of any actions taken under section 6.2A.4 or 6.2A.5 will be sent to the *OEB* and the *transmitter, distributor* and/or other *market participant* to whose *facilities* the *market participant's facilities* are *connected*.	Following 6E.09	None	None	Notice of any actions taken is issued to the *OEB* and the *transmitter, distributor* and/or other *market participant* to whose *facilities* the *market participant's facilities are connected*
6E.12	Issue de-registration order with *disconnection order*.	The *IESO* issues a de-registration order to the *market participant,* detailing: • the evidence on which the de-registration order is based;	Upon determination in Step 6E.07 that a de-registration order is appropriate or within 20 *business*	De-registration Order "*Disconnection Order*" (IMO-FORM-1302)	E-mail followed up with hard-copy via courier. *IESO* public Web site.	Deregistration Order issued and "Disconnection Order" issued if applicable

Ref	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
		• the effective date of de-registration; • the obligations of the *market participant*; • process for reapplying for registration of the *facilities* At the same time that a de-registration order is issued to the *market participant*, a *disconnection order* may be issued to the *transmitter*(*s*), *distributor*(*s*) or other *market participant* to whose *facilities* the *market participant* is *connected*.	*days* from the date the *suspension order* was issued.	Public notification of De-registration.		
6E.13	Receive de-registration order.	The *market participant* receives the de-registration order. As well as notification, that a *disconnection order* has been issued to the relevant *transmitter*(*s*), *distributor*(*s*) or other *market participant*.	Following Step 6E.12.	None	None	De-registration order received by the *market participant*.
6E.14	Receive de-registration order and *disconnection order* if issued.	The *IESO* shall provide a copy of the de-registration order, and the *disconnection order* if issued, to the *OEB* and the *transmitter(s)*, *distributor(s)* and/or other *market participant(s)* to whose *facilities* the *market participant* is connected.	Following Step 6E.12.	None	None	Receipt of de-registration order and *disconnection order* if issued..

Appendix A: Forms

This appendix contains a list of forms used in the Treatment of Compliance Issues process, which are available on the *IESO*'s public Web site (http://www.ieso.ca/). The forms included are as follows:

Form Name	Form Number
Non-Compliance Event Report	IMO-FORM-1253
Notice of Intent to Suspend	IMO-FORM-1260
Notice of Hearing with Board of Directors	IMO-FORM-1265
Other Order	IMO-FORM-1268
Suspension Order	IMO-FORM-1261
Disconnection Order	IMO-FORM-1302
Modification of Suspension Order	IMO-FORM-1264
Lift of Suspension Order	IMO-FORM-1263
Lift of Disconnection Order	IMO-FORM-1434
Notice of Intent to Terminate Market Participant	IMO-FORM-1266
Notice of Intent to De-register Facilities	IMO-FORM-1301
Termination Order	IMO-FORM-1267

Appendix B: Events of Default

The *market rules* (Chapter 3, section 6.3.1) sets out that an *event of default* occurs if a *market participant* or the person that has provided *prudential support* in relation to the *market participant*:

- does not make a payment in full required under the *market rules* when due;
- fails to provide payment in full of any amount claimed by the *IESO* under any *prudential support*;
- fails to provide *prudential support* required to be supplied under the *market rules* within the time required;
- has a licence (including a *licence*), permit or other authorization necessary to carry on its principal business suspended, revoked or otherwise cease to be in full force and effect, provided that where a *market participant* holds more than one *licence* and only one such *licence* has been suspended, revoked or otherwise ceases to be in full force and effect, the *event of default* and any action taken by the *IESO* with respect thereto shall relate only to such *licence*;
- ceases or threatens to cease to carry on its business or a substantial part of its business;
- becomes insolvent or is unable to pay all or some of its debts when they fall due for payment;
- seeks to enter into an arrangement, composition or compromise with, or makes an assignment for the benefit of, all or any class of its creditors;
- has a receiver or receiver and manager or person having a similar or analogous function under the laws of any relevant jurisdiction appointed in respect of any of its property that is used in or relevant to the performance of its obligations under the *market rules* or its *licence*;
- is the subject of an order appointing an administrator, liquidator, trustee in bankruptcy or person having a similar or analogous function under the laws of any jurisdiction;
- is wound up, dissolved, or otherwise has ceased to exist or is the subject of an application for winding up or dissolution, or any analogous procedure, under the laws of any jurisdiction, unless the notice of winding up or dissolution is discharged or withdrawn;
- ceases to satisfy any material requirement imposed upon it as a condition of its authorization to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid*.

– End of Section –

Appendix C: Audit Procedures

MACD is accountable for monitoring and enforcing compliance with *market rules*. For detailed procedures on the conduct of Reliability Standards audits by MACD, please see Market Manual 2.17: Compliance Auditing of Reliability Standards for Ontario Market Participants.

– End of Section –

Appendix D: Guidelines for Extraordinary Financial Penalties under the Ontario Electricity Market Rules

Financial Penalties Up to $1 million (Chapter 3, section 6.6.6A and 6.6.6B)

INTRODUCTION

Chapter 3[4] , section 6 of the "Ontario Electricity Market Rules" ("*market rules*" or "rules") describes the framework for the enforcement of compliance with the *market rules*, including the circumstances under which the *Independent Electricity System Operator* ("*IESO*") may impose sanctions, including financial penalties, for breaches of the rules. Section 6.2.7.5 specifies that financial penalties may only be imposed if:

> "…the *IESO* is satisfied that the breach could have been avoided by the exercise of due diligence by the *market participant* or that the *market participant* acted intentionally;"

Sections 6.6.1 – 6.6.7 specify the circumstances under which a financial penalty may be fixed within four penalty ranges: 1) up to $2,000, 2) up to $4,000, 3) up to $6,000, and 4) up to $10,000.

Section 6.6.6A allows the *IESO* to impose a financial penalty in excess of these amounts, up to $1 million per occurrence.

The purpose of these guidelines is to describe how the enforcement arm of the *IESO*, the Market Assessment and Compliance Division ("MACD"), will fix the amount of a financial penalty for matters falling under section 6.6.6A which reads as follows:

> "The *IESO* may impose on a *market participant* a financial penalty in excess of the amount otherwise provided for in section 6.6.6 and no greater than $1,000,000 per occurrence, where:
>
> 6.6.13.1 the *market participant* has breached a *market rule* while a declaration that the *IESO-controlled grid* is in an *emergency operating state* or a *high-risk operating state* was in effect;
>
> 6.6.13.2 the *market participant* breached a *market rule* while a declaration that *market operations* have been suspended was in effect;
>
> 6.6.13.3 the *IESO Board* determines that the impact of the *market participant*'s breach of a *market rule* on either the *IESO-administered markets* or the *reliability* of the *integrated power system* is particularly severe; or

[4] All section references in this document refer to Chapter 3 of the Market Rules

6.6.13.4 the rate of recurrence of non-compliance by the *market participant* with the *market rules* is of such frequency or duration as to warrant the imposition of a higher financial penalty."

The central feature of the guidelines is a table or matrix ('Section 6.6.6B Penalty Matrix') identifying dollar ranges from $2,000 to $1 million, according to the assessment of the impact ('impact level') of the breach, as well as its severity and the record of non-compliance ('breach history') of the party, and any adjustments. A final penalty amount within the selected range is determined based on an assessment of a set of factors, including those that may be aggravating or mitigating. The underlying principle of the guidelines is that their application results in a financial penalty that bears a direct relationship to the seriousness of the breach.

In keeping with well-established principles of enforcement and adjudication, the guidelines provide a measure of the likely size of a financial penalty for a given breach, but they are not a mathematical formula or algorithm. The final penalty amount will always be an exercise of judgement based on an assessment of the facts of the particular case.

To ensure that the party being assessed a financial penalty under section 6.6.6A has an adequate opportunity to bring forward relevant information and evidence, the guidelines also specify that MACD's review provides the party with an opportunity to meet and provide written comments on MACD's preliminary assessment. This mirrors the procedures in the rules for determining whether a breach of the rules has occurred.

SCOPE

These guidelines come into play after a breach has been determined. The finding of a breach and the fixing of a financial penalty in the range allowed for under section 6.6.6A are separate matters. These guidelines address the latter.

These guidelines address the fixing of a financial penalty in the range allowed for under section 6.6.6A. They do not speak to whether a breach qualifies for consideration to be assessed a financial penalty under section 6.6.6A.

These guidelines apply to both *market participants* and the *IESO*.

OVERVIEW

Steps

The magnitude of financial penalty levied on a party, will be determined in two steps:

STEP 1 - Penalty Range,

1. Impact Level
2. Non-compliance Level

STEP 2 – Fixing Penalty Amount

1. Base Amount
2. Final Penalty Amount

DESCRIPTION OF STEPS

A detailed description of the principles used in each step below is provided in the section titled "Description of Principles".

Step 1 - Penalty Range

There are two parts to establishing the penalty range:

1. Impact Level
   The impact level is determined by examining all the impacts of the breach under investigation and selecting an appropriate impact level.
2. Non-Compliance Level
   The non-compliance level is determined by assessing the level for: 1) Breach History and 2) Severity, and selecting the higher of the two, and finally, deciding whether any increasing or decreasing adjustments are appropriate. Among the adjustments that would increase the non-compliance level are: 1) Lack of Due Diligence, 2) Benefit, and 3) Corporate Intent.

   For example, if the breach history is assessed as 'moderate' and the severity is assessed at 'high', the non-compliance level will be 'high' unless an adjustment, such as corporate intent to breach the *market rule*, applies. In this case, evidence of corporate intent to breach the rule would raise the non-compliance level from 'high' to 'severe'.[5]

The appropriate penalty range (bounded by the minimum and maximum amounts) is identified from the intersection of the chosen non-compliance level and the impact level of Table 1.

Table D-1: Section 6.6.6B Penalty Matrix

[5] Table 3 in the next section shows the non-compliance levels associated with the different assessments of Breach History and Severity.

	Non-Compliance Level (Severity and Breach History)							
Impact Level	**Low**		**Moderate**		**High**		**Severe**	
	Range Limit		Range Limit		Range Limit		Range Limit	
	Min	Max	Min	Max	Min	Max	Min	Max
Low Little or None	$2,000	$25,000	$2,000	$50,000	$3,000	$75,000	$5,000	$100,000
Medium Material	$2,000	$100,000	$4,000	$250,000	$6,000	$450,000	$10,000	$600,000
High Severe	$4,000	$250,000	$8,000	$500,000	$12,000	$750,000	$20,000	$1,000,000

Note: matrix can be used to assess penalties on a per breach basis or as one aggregated breach.

Step 2 – Fixing Penalty Amount: Case Factors

MACD will establish a base amount within the penalty range selected from step 1, by examining Impact and Time Horizon of the breach. In fixing a final penalty amount, MACD will also consider additional case factors which can result in an increase or decrease from the base amount.

1. Base Amount

   The outcome of Step 1, will result in the selection of a penalty range from Table 1 within which a base amount will be selected. MACD will consider the following two case factors when fixing a base amount from the relevant penalty range:

   a. Impact Assessment
      The impact assessment will be based on all impacts of the breach under investigation. The same criteria are applied as have been used to establish the impact level in Step 1.

   b. Time Horizon
      The analysis will assess the degree of immediate risk posed by the breach under investigation.

2. Final Penalty Amount

Once a base amount is determined, the final penalty amount, within the selected range in Step 1, will be determined after assessing the additional case factors. Each factor can result in an increase (aggravating) or decrease (mitigating) from the base amount.

DESCRIPTION OF PRINCIPLES

Step 1

Impact Level

The impact level determined in Step 1 will be established after consideration of:

- the impact of the breach on other *market participant(s)*;
- the actual or potential impact of the breach on the *IESO-administered markets* as a whole;
- the actual or potential impact of the breach on the *reliability* of the *integrated power system*; and
- any sanctions that may be imposed on the *IESO* by a *standards authority* as a result of the breach.

Once all these impacts are considered, an impact level commensurate with the descriptions of each level in Table 2 is selected.

For breaches of *reliability standards*, *NERC* will be assigning an impact level (violation risk factors) to each requirement of a standard. MACD will take into consideration the *NERC* violation risk factor in determining the impact level as the assessment of the impact the breach has had on *reliability*. Violation risk factors for all standards have yet to be assigned. In the absence of these, MACD will make best efforts to assign a violation risk factor in accordance with the principles used by *NERC* or *NPCC* (FERC Order RR07-9-000 and RR07-1-000, issued May 18, 2007, paragraph 9). Where violation risk factors have yet to be assigned by *NERC*, MACD will make public the impact level used in the application of these guidelines.

Table D-2: Impact Levels

Impact Level	Description
Low	The potential or actual impact of a breach was negligible or there was no impact.
Medium	The potential or actual impact of a breach was material.
High	The potential or actual impact of a breach was severe.

Non-Compliance Levels

The non-compliance level is determined by: a) selecting, from Table 3, the higher level determined by examining both Breach History and Severity, and b) considering any increasing or decreasing adjustments.

Table D-3: Non-Compliance Level Criteria:

Non-Compliance Levels				
	Low	Moderate	High	Severe
Breach History	Zero or one	Two	Three	Four
Severity	Low	Moderate	High	Severe

1. Breach History

This criterion considers the compliance history of a party with breaches that are the same or related obligations to the breach under investigation. As an alternative to considering these breaches in determining the non-compliance level (Step 1), they can be considered in Step 2. MACD will not use a mechanical approach in determining the contribution to a party's breach history. Rather, MACD will have regard for all of the circumstances surrounding a party's breach history, including the significance of the breach history relative to the party's number of assets or *facilities* and the amount of time that has passed since the breaches occurred. MACD will also consider the extent to which a party has remedied past breaches or executed mitigation plans and the time required to do so. For example, related past breaches that have not occurred recently, that are less serious, or that were remedied quickly and effectively, are likely to be excluded from consideration.

The notional weights assigned these past breaches is described below:

a. Failure to Comply with Orders
Upon a finding of breach, MACD can issue orders which can include but are not limited to any action necessary to remedy a breach of the *market rules* as set out in section 6.2.7. Any one failure to comply with an order will contribute to a party's breach history by a count of 'one'.

b. Continuing Breaches
A breach is described as 'continuing' if a party has been found in breach of an obligation and the same breach remains unresolved. Any one continuing breach will contribute to a party's breach history by a count of 'one'.

c. Consecutive Breaches and Repetitive Breaches

Each *market rule* obligation may explicitly state a time frame in which the obligation must be met. For example, a *market rule* may explicitly require that verifications be conducted annually. With breaches of this obligation that occur in 2003 and 2004, the 2004 breach would be considered 'consecutive'. If the breach under investigation is 'consecutive', the past breach will contribute by a count of 'one' to breach history.

In contrast, if breaches of the same obligation occur in 2003 and 2005, the 2005 breach is considered 'repetitive'. Two repetitive past breaches contribute by a count of 'one' to a party's breach history. In conjunction with a failure to execute mitigation plans two repetitive breaches may contribute to breach history by a count of 'two'.

Other failures may be event driven such as *operating reserve* activations. Consecutive breaches may occur two weeks apart or 2 hours apart depending on the timing of the activation request. Where the *market rules* do not explicitly state the time frame in which the requirement must be met, MACD will determine whether recurrent breaches are consecutive or repetitive.

In some *reliability standards*, there is a 'violation reset time' for a standard, which describes the period of time generally required for a party to continue operations without incidence of further breach of the *reliability standards*, in order to avoid or minimize consideration of party's previous breach history for sanctioning purposes in the event of a subsequent breach. Breaches that occur within the 'violation reset time' are likely to be considered 'consecutive' breaches. Conversely, breaches outside the 'violation reset time' are likely to be considered 'repetitive' breaches.

2. Severity of Breach

Severity will consider the number of documented instances of non-compliance (not necessarily established breaches) and the extent of the breach. Two such examples are provided below.

Example One:

Severity may be established by using a rate of non-compliance. The rate is indicative of severity and may be set at 90% or above for good performance and 75% or below for unacceptable performance. For 75% performance the non-compliance level maybe considered "severe" depending on the nature of the requirement.

Example Two:

Duration may be considered in establishing the severity of a breach. For example, the length of time a party fails to establish direct communication with the *IESO* after a contingency is an indicator of severity. The requirement specifies that contact be made within 5 minutes. The severity of the failure would be relative to the 5 minutes requirement and maybe considered severe if it exceeds 15 minutes. In contrast, the failure to upgrade a *metering installation* may be considered low if the duration of the breach is less than one month.

As illustrated in these examples, the severity of a breach must be viewed within the context of the requirement. The examples are not exhaustive of the type of assessment MACD will deploy to determine severity.

In relation to breaches of *reliability standards*, *NERC* is planning to define for each of its standards four levels that attempt to capture the severity of non-compliance, to be known as the 'Violation Severity Level'. Where a Violation Severity Level exists, MACD will consider it as its assessment of severity to the extent it captures all dimensions of the severity of the breach.

3. Adjustments

Once an initial non-compliance level is determined it can be adjusted to a higher or lower level (adjusted to the right or left, respectively, at the same impact level). If any one or more of the following three factors are present, adjustments will be made to a higher non-compliance level (adjust to the right) along the matrix.

a. Lack of Due Diligence

This adjustment will increase the non-compliance level when the severity of a breach is increased from where it otherwise would have been where there is a reasonable expectation that action should have been taken by a party. For example, an increase will occur when detection and mitigation should have taken place sometime before the breach was discovered, either through the exercise of due diligence or other periodic actions mandated under the *market rules*, or through *good utility practices*. For example, the duration of a breach may be extended as a result of inaction by a party. When the duration of a breach is increased as a result of the lack of due diligent actions as described above, the non-compliance level can be increased above the initial selection.

b. Benefit

The non-compliance level may be increased if any benefit was obtained or may have been obtained by the *market participant* as a result of the breach. Assessment of this factor deters parties from making economic choices to breach *market rules*. It also sends a clear message that parties participating in the market must establish a compliance culture within their organizations and economic choices to breach are not supported as an acceptable alternative to compliance. Adjustments will be made commensurate with the benefit gained by the party.

c. Corporate Intent

A breach will be considered deliberate if the facts of a case point to a *market participant* knowingly breaching a *market rule*. Where there is an understood corporate practice or communicated corporate intent to breach, the non-compliance level established may be increased above the initial selection.

Step 2

Fixing Penalty Amount

A base penalty amount is established within the range selected in step 1 by examining impact and time horizon. The final penalty amount will be fixed within the range selected from step 1 following consideration of the additional factors listed below. Each factor can result in an increase or decrease from the base penalty amount.

1. Base Penalty Amount

Once a range is determined in step 1, a base penalty amount is set within the range based on an assessment of impacts and time horizon described below.

The impact assessment is exactly the same as determining the 'impact level' under Step 1.

a. Impact Assessment

The contribution of 'impact' to establishing the base penalty amount is carried out after consideration of:

- impact of the breach on other *market participant*(s);
- the actual and potential impact of the breach on the *IESO-administered markets* as a whole;
- the actual and potential impact of the breach on the *reliability* of the *integrated power system*; and
- any sanctions that may be imposed on the *IESO* by a *standards authority* as a result of the breach

b. Time Horizon

The rules have requirements which span a range of time frames. Some requirements pertain to planning activities and are conducted years in advance. If these are breached, they pose a future threat to *reliability* or the market. Conversely, breaches affecting real-time grid operations or market outcomes pose an immediate threat. Breaches which pose an immediate threat would result in higher base penalty amounts than breaches pertaining to planning activities, all other factors remaining equal.

Reliability standards' requirements fall into similar timeframes long term planning, operations assessment, operations planning, real-time operations, and same day operations. *NERC* and *NPCC* have linked these categories with the immediacy of the threat that breaches pose to *reliability*. MACD will consider these linkages in establishing a base amount for breaches which cause *reliability* impacts.

2. Final Penalty Amount

Additional Case Factors – Aggravating and Mitigating

The final penalty amount will be fixed within the range selected from step 1 considering the additional factors listed below. Each factor can result in an increase or decrease from the base penalty amount within the identified range:

a. the circumstances in which the breach occurred;
b. the severity of the breach;
c. the extent to which the breach was inadvertent, negligent, deliberate or otherwise;
d. the length of time the breach remained unresolved;
e. the actions of the *market participant* on becoming aware of the breach;
f. whether the *market participant* disclosed the matter to the *IESO* on its own or whether it was prompted to do so;
g. any benefit that the *market participant* obtained or may have obtained as a result of the breach;
h. any previous breach by the *market participant* of the *market rules* or of the conditions of its *licence*;
i. the actual or potential impact of the breach on other *market participants*;
j. the actual or potential impact of the breach on the *IESO-administered markets* as a whole;
k. the actual or potential impact of the breach on the *reliability* of the *integrated power system*;
l. any sanctions that may be imposed on the *IESO* by a *standards authority* as a result of the breach;
m. the immediacy of the threat the breach poses to the *reliability* of the *integrated power system* or the *IESO-administered market*;
n. presence and quality of the *market participant*'s compliance program;
o. whether on its own initiative, a *market participant* has undertaken to reasonably compensate the *IESO-administered market* for the value of any benefit it obtained as a result of the breach; and
p. such other matters as the *IESO* considers appropriate.

Examples of "other such matters as MACD considers appropriate" are past case communications concerning past remedies implemented for related breaches, the level of cooperation provided by the party in resolving the investigation and failure of a party to comply with a directive or order given by the *IESO*.

DUE PROCESS ADDITIONS

For financial penalties assessed pursuant to these guidelines, once MACD has found a breach of the *market rules*, MACD will provide the party under investigation an opportunity to provide additional information and comment on the preliminary penalty assessment through written submissions. Prior to issuing the final "Notice of Non-compliance", MACD will issue a draft notice to the party with an attached preliminary penalty assessment.

– End of Section –

References

Document ID	Document Title
MDP_RUL_0002	Market Rules for the Ontario Electricity Market
MDP_MAN_0002	Market Manual 2: Market Administration, Part 2.0: Market Administration Overview
MDP_PRO_0023	Market Manual 2: Market Administration, Part 2.7: Treatment of Market Surveillance Issues
MDP_PRO_0045	Market Manual 5: Settlements, Part 5.4: Prudential Support
MDP_PRO_0035	Market Manual 5: Settlements, Part 5.6: Physical Markets Settlement Invoicing
MDP_PRO_0047	Market Manual 5: Settlements, Part 5.8: Financial Markets Settlement Invoicing
MDP_PRO_0036	Market Manual 5: Settlements, Part 5.9: Settlement Payment Methods and Schedule
MDP_PRO_0016	Market Manual 1: Market Entry Maintenance and Exit Part 1.2 Facility Registration, Maintenance and De-registration
MDP_PRO_0022	Market Manual 1: Market Entry Maintenance and Exit Part 1.1 Participant Authorization, Maintenance and Exit
IMO_CAT_0002	Market Manual 2: Market Administration Part 2.14: Information Confidentiality Catalogue

– End of Document –

Exhibit "Q"

IESO Market Manual 5.5: Physical Markets Settlement Amounts dated March 6, 2024

Exhibit "Q"

to the Affidavit of Robin Doolittle

Sworn before me on October 29, 2025, in accordance with O. Reg. 431/20, Administering Oath or Declaration Remotely



Commissioner for Taking Affidavits
(or as may be)

October 29, 2025

Keith Edward Hickey, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.

Expires June 24, 2027.

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PROCEDURE

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Market Manual 5: Settlements

Part 5.5: Physical Markets Settlement Amounts

Issue 92.0

Archive

This procedure describes the processes to issue, retrieve and dispute *physical markets settlement statements*.

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84.0	Updated for Baseline 46.0	September 15, 2021
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91.0	Updated for Baseline 50.1	November 29, 2023
92.0	Updated for Baseline 51.0	March 6, 2024

Related Documents

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Table of Changes

Reference (Section and Paragraph)	Description of Change
1.6.7.1	Edits made to reference Ontario Regulation 53/05, "Payments Under Section 78.1 of the Act" under the *Ontario Energy Board Act,* 1998 for list of OPG's regulated assets.

Archive

Market Manuals

The *market manuals* consolidate the market procedures and associated forms, standards, and policies that define certain elements relating to the operation of the *IESO-administered markets*. Market procedures provide more detailed descriptions of the requirements for various activities than is specified in the *market rules*. Where there is a discrepancy between the requirements in a document within a *market manual* and the *market rules*, the *market rules* shall prevail. Standards and policies appended to, or referenced in, these procedures provide a supporting framework.

Market Procedures

The "Settlements Manual" is Volume 5 of the *market manuals*, where this document forms "Part 5.5: Physical Markets Settlement Statements".

A list of the other component parts of the "Settlements Manual" is provided in "Part 5.0: Settlements Overview", in Section 2, "About This Manual".

Structure of Market Procedures

Each market procedure is composed of the following sections:

1. **"Introduction"**, which contains general information about the procedure, including an overview, a description of the purpose and scope of the procedure, and information about roles and responsibilities of the parties involved in the procedure.
2. **"Procedural Work Flow"**, which contains a graphical representation of the steps and flow of information within the procedure.
3. **"Procedural Steps"**, which contains a table that describes each step and provides other detail related to each step.
4. **"Appendices"**, which may include such items as lists of forms, standards, policies, and agreements.

Conventions

The *market manual* standard conventions are defined in the "Market Manual Overview" document.

In this document, "we" and "us" refers to the *IESO*; "you" refers to *market participants* unless specifically identified otherwise.

– End of Section –

Archive

1. Introduction

1.1 Purpose

This procedure provides additional information regarding certain *settlement amounts* relating to the *physical markets*.

For the purposes of this procedure, all references to *physical markets* refer to:

- the *real-time market* for *energy*, which consists of:
  - a market for *energy*; and
  - a market for several classes of *operating reserve*;
- *procurement markets*, which consists of:
  - markets for *contracted ancillary services*, including: *reactive support* and *voltage control*, *regulation* service and *black start capability*;
  - a market for *reliability must-run contracts*; and
- the *transmission rights* (*TR*) market, except for *settlement amounts* relating to the purchase or sale of a *transmission right* in any round of a *TR auction*.

1.2 Scope

This document provides a summary and additional information regarding certain *settlement amounts* relating to the *physical markets*.

The procedural work flows and steps serve as a roadmap and reflect the requirements set out in the *market rules* and *IESO* policies and standards.

This procedure contains three parts:

- Section 1 contains a summary and additional information relating to certain *settlement amounts*;
- Section 2 describes the main actions of the procedure in the procedural work flow; and
- Section 3 presents the procedural steps.

This procedure applies only to the *IESO's physical markets*.

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1.6 Special Settlement Activities

Special exemptions, rebates and *settlement* programs are available to eligible *market participants*. We describe them in the following sub-sections.

1.6.1 Generation Station Service Rebate

Some *generation facilities* in the *IESO-administered markets* consume *energy* as *generation station service*. *Metered market participants* for certain *generation facilities* are eligible for a reimbursement of the *hourly uplifts* and non-hourly *settlement amounts* related to AQEW consumed as *generation station service*. Refer to Chapter 9, Sections 2.1A.9-2.1A.14 of the *market rules* to find the eligibility requirements and the specific conditions under which this rebate applies.

If you[1] believe that your *generation facility* is eligible for a *generation station service* rebate, you should:

- download IMO_FORM_1419 "Application for Designation of a Facility for Generation Station Service Rebate" from our web site;
- complete all applicable sections; and
- submit the form to us.

We will:

- review your application;
- request additional information in order to assess the application, if necessary;
- determine if your *generation facility* meets the requirements for the rebate designation; and
- notify you in writing of our determination.

If you meet the requirement for the rebate designation, we will adjust the *hourly uplifts* and non-hourly *settlement amounts* that may have accumulated at the *generation station service delivery point* during the periods where the eligible *generation facility* was a net injection of *energy* into the *IESO-controlled grid*.

Reimbursement amounts are calculated at month-end and applied to the last *trading day* of the month on *settlement statements*, as applicable, for each *generation facility* as *charge type* 119 – Station Service Reimbursement Credit.

The offsetting *charge type* 169 – Station Service Reimbursement Debit is included on *settlement statements*, as applicable, of all load customers for the last *trading day* of the month.

[1] In this Section 1.6.1, "you' refers to a *metered market participant*.

Archive

1.6.1A Electricity Storage Station Service Rebate

Electricity storage facilities in the *IESO-administered markets* consume *energy* as *electricity storage station service*. *Metered market participants* for certain *electricity storage facilities* are eligible for a reimbursement of the *hourly uplifts* and non-hourly *settlement amounts* related to AQEW consumed as *electricity storage station service*. Refer to Chapter 9, Sections 2.1A.13A and 2.1A.13A.3 of the *market rules* to find the eligibility requirements and the specific conditions under which this rebate applies.

If you[2] believe that your *electricity storage facility* is eligible for this rebate, you should:

- download IMO_FORM_1419 "Application for Designation of a Facility for Generation Station Service Station Service Rebate" from our web site;[3]
- complete all applicable sections; and
- submit the form to us.

We will:

- review your application;
- request additional information in order to assess the application, if necessary;
- determine if your *electricity storage facility* meets the requirements for the rebate designation; and
- notify you in writing of our determination.

If you meet the requirement for the rebate designation, we will adjust the *hourly uplifts* and non-hourly *settlement amounts* that may have accumulated at the *electricity storage station service delivery point* during the periods where the eligible *electricity storage facility* was a net injector of *energy* into the *IESO-controlled grid*.

Reimbursement amounts are calculated at month-end and applied to the last *trading day* of the month on *settlement statements*, as applicable, for each *electricity storage facility* as *charge type* 119 – Station Service Reimbursement Credit.

The offsetting *charge type* 169 – Station Service Reimbursement Debit is included on *settlement statements*, as applicable, of all load customers for the last *trading day* of the month.

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Note:	The section 'Debt Retirement Charge (DRC)' has been removed. The archived section can be found in Appendix E.14.

1.6.3 Intentionally Left Blank

Note:	The section 'OPG Rebate Requests for Additional Payments or Returns' has been removed The archived section can be found in Appendix E.8.

[2] In this Section 1.6.1 and 1.6.2, "you' refers to a *metered market participant*.

[3] *Electricity storage participants* are to use the Generation Station Service Form

1.6.4 Intentionally Left Blank

Note: The section 'Real-time Generation Cost Guarantees' has been removed effective August 1, 2017. Content relating to the GCG program can be found in Market Manual 4: Market Operations Part 4.6: Real-Time Generation Cost Guarantee Program (PRO_324). The archived section can be found in Appendix E.7.

1.6.5 Administrative Pricing Event

This section applies only when an "Administrative Pricing Event" does not exceed 48 *dispatch intervals* and the *market schedules* and prices were established by the "copy forward/back" methods[4].

For situations where *administrative prices* were applied beyond 48 *dispatch intervals*, please refer to "Market Manual 4.3: Real Time Scheduling of the Physical Markets".

Where an "Administrative Pricing Event" does not exceed 48 *dispatch intervals*, some *market participants* may not be adequately compensated[5]. Should this occur, you may only submit a *notice of disagreement* within six *business days* after your *preliminary settlement statement* has been issued to request *settlement amount* adjustments.

- For the case where you receive negative CMSC amounts, and all conditions stated in Chapter 7, Sections 8.4A.13 and 8.4A.14 of the *market rules* are met, we will apply *settlement amount* adjustments that offset the original negative CMSC amounts. The adjustments will appear under *charge types* 105, 106, 107 or 108 on a subsequent *settlement statement* for the trading day. For the case where you were not compensated enough in the net *energy market settlement*, and all conditions stated in Chapter 7, Section 8.4A.15, 8.4A.16 of the *market rules* are met, we will apply additional compensation adjustments, based on the equations found in the Chapter 7, Section 8.4A.16, as the case may be. Compensation will appear under *charge type* 113 on a subsequent *settlement statement* for the *trading day.* In the same *settlement statement,* we will recover all paid compensations from the market (on a pro-rata basis across all withdrawals), under *charge type* 163.

Sections 8.4A.13 and 8.4A.15 of the *market rules* further specify that we are not required to perform the analysis if either the CMSC adjustment or the additional compensation adjustment is not material.

The total hourly CMSC adjustment or the total hourly additional compensation for a given *delivery point* must equal or exceed a materiality threshold amount of $ 50.00 per hour, per *delivery point* and the submission total must exceed $400.00 for each administrative pricing event request.

Specifically, in cases where the CMSC adjustment request or the additional compensation request falls below the threshold amount, we will not perform any further analysis and will not apply any adjustments.

Please refer to the Section 1.5 "Submitting a *Notice of Disagreement"* in this *market manual* for a description of guidelines and supporting documentation (the *market participant* must submit IMO_FORM_1549 along with a *notice of disagreement*) that must be provided as part of the *notice of disagreement* process.

[4] See Chapter 7, Section 8.4A.5 of the *market rules.*

[5] See Chapter 7, Section 8.4A.13, 8.4A.14, 8.4A.15 and 8.4A.16 of the *market rules.*

1.6.6 Transmission Service Charges for Embedded Generation

If, as a host *transmission customer*, you have an *embedded generation facility* that:

- was approved after October 30, 1998;
- is not separately registered as a *generation facility* in the *IESO-administered markets*;
- meets the applicable Ontario Transmission Rate Schedule requirement; and
- is rated at greater than or equal to 1 MW (2 MW for renewable *generators*[6]) and less than 20 MW,

then you may choose to meet the existing wholesale *metering installation* standards or to use the alternative standard in Chapter 6 Section 4.5 of the *market rules*. The alternative standard allows the host *transmission customer* to register a *meter point* for the *embedded generation facility* without a corresponding wholesale physical *meter*.

A *transmission customer* that chooses the alternative *metering installation* standard for *embedded generation* must determine the annual adjustment dollar value for the applicable *transmission service charges*. The adjustment amount must be agreed to by the *transmitter* and submitted to us. In the event that we do not receive this information in a timely manner, we will use the installed *maximum continuous rating* (as registered) for the *embedded generation facilities* to determine an adjustment amount.

1.6.6.1 Calculation Methodology

Line and transformation connection service charges need to be calculated monthly for all *delivery points* with *embedded generation facilities* registered under the Alternative Metering Installation Standards for Embedded Generation Facilities (Chapter 6, Section 4.5 of the *market rules*).

On a monthly basis, the host *transmission customer* will:

- download the *participant transmission tariff* data file;
- add the hourly generation values for the *embedded generator* to the hourly demand data for the *delivery point* associated with the *embedded generation*; and
  - determine the new monthly maximum hourly peak value for the *delivery point* and compare it to the settled monthly maximum hourly peak value; if the new peak is higher, then:
  - calculate the incremental line connection service charges (if applicable) by multiplying the line connection tariff by the incremental peak value; and
  - calculate the incremental transformation connection service charges (if applicable) by multiplying the transformation connection tariff by the incremental peak value.

On an annual basis, the host *transmission customer* must sum all monthly line and transformation connection service charges and obtain agreement of the *transmitter* to the proposed adjustment, if any. Submit the totals to us via the Submit Settlement Claim action available through Online IESO within the month of April following calendar year end.

[6] Renewable generation refers to electricity produced by wind, solar, small hydroelectric, biomass, bio-oil, bio-gas and landfill gas.

1.6.7 Regulated Price Plan, Regulated Generation, NUG Payments and Newly Contracted Generation

The *Electricity Restructuring Act, 2004* (Bill 100) introduced a number of important changes to the electricity market that affect both the *IESO* and *market participants*. These changes include:

- the establishment of the former *Ontario Power Authority* (*OPA*);
- a regulated payment to *generators* prescribed by regulations;
- payments to *Ontario Electricity Finance Corporation (OEFC)* for non-utility *generator* (NUG) contract amounts;
- payments to the IESO (former *OPA)* for renewable generation and for clean generation and demand-side projects awarded as a result of a Request for Proposal (RFP) process;
- the establishment of regulated *consumer* prices beginning in April 2005, known as the Regulated Price Plan (RPP) (RPP prices are set by the *Ontario Energy Board (OEB)* from time to time); and
- the creation of a "Global Adjustment" amount, which is the difference between the contract amounts and market payments for OPG regulated generation, NUG generation and RFP contracted generation and demand-side management.

Implementing these changes required the creation of new *charge types* within the IESO's *settlements* system. The *charge types* are listed in the "IESO Charge Types and Equations" document and are comprised of charges that are payable to or from *market participants* with, in most cases, the corresponding offsets payable by the IESO.

Ontario Regulation 398/10 made under the *Electricity Act, 1998* which amended O. Reg. 429/04 significantly changed the Global Adjustment, creating two classes of *market participants* with different approaches to the distribution of the global adjustment costs. The regulation further added the costs related to *distributor* developed conservation and demand management programs to the Global Adjustment pool.

1.6.7.1 Regulated OPG Nuclear and Baseload Hydroelectric Generation

Under the *Electricity Restructuring Act, 2004* and subsequent regulations, OPG's nuclear and baseload hydroelectric assets will receive a regulated price. A list of OPG's regulated assets can be found in the Ontario Regulation 53/05 made under *Ontario Energy Board Act, 1998*.

We have created two *charge types* to implement the adjustments for nuclear generation and for baseload hydroelectric generation. The adjustments are the difference between:

- the *market prices* paid to regulated hydroelectric generation and nuclear generation using the existing *settlements* process; and
- the regulated fixed rate that the regulated nuclear generation and a portion of output of the regulated hydroelectric generation should receive.

In essence, the adjustment is the difference between the amount OPG would have received at *market prices* and the amount calculated at regulated prices. The *settlement* of the hydroelectric generation assets includes an adjustment based on the average *market prices* for the month. We use c*harge type* 144 "Regulated Nuclear Generation Adjustment Amount" to adjust payments to OPG with respect to the regulated nuclear generating stations, and *charge type* 145 "Regulated Hydroelectric Generation Adjustment Amount" to adjust payments to OPG with respect to the regulated hydroelectric generating stations.

Archive

Amounts calculated under *charge types* 144 and 145 will be set off against the IESO, using the corresponding *charge types* 194 and 195 respectively. The regulated nuclear generation amounts (i.e., *charge types* 144 and 194) are automatically generated by CRS and appear as *settlement* details on both OPG's and the IESO's *settlement statements*. The regulated hydroelectric generation amounts (i.e., *charge types* 145 and 195) are calculated monthly and included as a combination of both automatic calculations and manual line items on both OPG's and the IESO's *settlement statements*.

1.6.7.2 OEFC Adjustment

Section 78.2 of Bill 100 states that the *OEFC* will be paid contract amounts for all NUG output. We use current *settlemen*t processes to pay *OEFC* at wholesale *market prices* for all NUG output delivered to the *IESO-controlled grid*. The difference between the monies paid out by *OEFC* to all NUGs and the monies received from us and *distributors* (embedded NUGs) for all NUG output is submitted to us on a monthly basis using the settlement form "NUG Adjustment Amount Information" available within Online IESO.

The monthly amount submitted by *OEFC* is included as a manual line item on *OEFC's settlement statements* for the last *trading day* of the month. Any amount submitted as a post final adjustment will be settled on the *preliminary settlement statement* for the last *trading day* of the month. The *charge type* used is 143 "NUG Contract Adjustment Settlement Amount".

To balance the market, the corresponding setoff, *charge type* 193 "NUG Contract Adjustment Balancing Amount", is entered as a manual line item on the IESO's *settlement statements* for the last *trading day* of the month.

1.6.7.3 Clean Generation and Demand-Side Projects Settlement

The IESO has entered into procurement contracts with certain suppliers for clean *energy* supply and demand-side management or demand response, to promote the use of clean *energy* and to assist the government in achieving its goals in electricity conservation.

The difference between the contracted price and the wholesale *market price*, with respect to the clean generation or load reduction contracts, is settled by the *IESO*. It is included as a manual line item on the IESO's *settlement statement* for the last *trading day* of the month. The *charge type* is 1400 "OPA Contract Adjustment Settlement Amount".

The corresponding setoff, *charge type* 1450 "*OPA* Contract Adjustment Balancing Amount", is entered as a manual line item on the *IESO's settlement statement* for the last *trading day* of the month to balance the market.

1.6.7.4 Renewable Generation Settlement

The *IESO* has entered into procurement contracts for renewable generation with certain suppliers. The difference between the contracted price and the wholesale *market price*, with respect to the renewable generation contracts, is settled by the *IESO*.

1.6.7.5 Renewable Generation Connection Compensation

Details relating to the implementation of a new cost recovery framework established by the Green Energy Act are set out in Ontario Regulation 330/09. This new framework allows local distribution companies to recover certain costs associated with the connection of new renewable generation to their local *distribution system* from all electricity *consumers* in Ontario (i.e., renewable generation contracted after the *OEB* issued its revised cost responsibility rules on October 21, 2009). These costs are approved by the *OEB*.

Archive

The portion of aggregate renewable generation connection compensation that you are charged is determined by your net volume of electricity withdrawn (AQEW) from the *IESO-controlled grid* during the month, plus, if you are a licensed *distributor*, the volume of embedded generation you are reporting using the settlement form available within Online IESO, divided by the sum of all amounts (net electricity withdrawn and embedded generation) for every *market participant*. (The volume of electricity supplied to Fort Frances Power Corporation Distribution Inc. by Abitibi-Consolidated Inc. is excluded from the calculation).

The portion of aggregate renewable generation connection compensation that each eligible *distributor* receives is determined by the *OEB*.

Charge type 1413 "Renewable Generation Connection - Monthly Compensation Settlement Credit" will appear on the *settlement statements* of each eligible local distribution company for the last *trading day* of the month.

The corresponding debit, *charge type* 1463 "Renewable Generation Connection - Monthly Compensation Settlement Debit", is included on the *settlement statements* of all load customers for the last *trading day* of the month to balance the compensation credit.

1.6.7.6 Conservation and Demand Management Programs

Under section 78.5 of the *Ontario Energy Board Act, 1998*, the *IESO* must make payments to a *distributor* (or LDC) for amounts approved by the *OEB* relating to conservation and demand management (CDM). Specifically, these payments relate to the recovery of costs for Board-approved CDM initiatives that are undertaken by LDCs to meet the CDM targets set out in their licenses, and to associated performance incentives. The *IESO* will make these payments, as directed by the *OEB*, through *charge type* 1416 "Conservation and Demand Management – Compensation Settlement Credit". These payments will be recovered through the Global Adjustment.

Charge type 1416 "Conservation and Demand Management – Compensation Settlement Credit" will appear on the *settlement statements* of each eligible LDC for the last *trading day* of the month.

1.6.7.7 Regulated Price Plan

The Regulated Price Plan is an *OEB*-mandated pricing mechanism for low-volume and designated *consumers*. There are three Regulated Price Plans: a tiered pricing structure with conventional meters, and two time-of-use (TOU) pricing structures with TOU meters (also known as "smart meters").

The tiered pricing structure sets a lower fixed price for *energy* consumption up to a monthly threshold amount, with consumption above this level at a higher price. The *OEB* adjusts both the threshold amount and prices once a year, for the period November 1 (year X) to October 30 (year X+1).

Archive

The time-of-use (TOU) pricing structures, which include the standard TOU and the ultra-low overnight (ULO), establish prices for *energy* based on when the *energy* is consumed. As with the tiered RPP, the *OEB* adjusts TOU prices once a year.

The categories for prices and consumption times under the standard TOU are on-peak, mid-peak, and off-peak.

1. On-peak reflects times when average *demand* is highest.
    a. The on-peak periods are from 7 a.m. to 11 a.m. and from 5 p.m. to 7 p.m. on winter weekdays[7], and from 11 a.m. to 5 p.m. on summer weekdays.
2. Mid-peak reflects the shoulder periods between on-peak and off-peak times.
    a. The mid-peak periods are from 11 a.m. to 5 p.m. on winter weekdays, and from 7 a.m. to 11 a.m. and from 5 p.m. to 7 p.m. on summer weekdays.
3. Off-peak reflects times when average *demand* is lowest.
    a. The off-peak periods are from 7 p.m. to midnight and midnight to 7 a.m. on winter and summer weekdays, and 24 hours (all day) on winter and summer weekends and holidays.

The categories for prices and consumption times under the ultra-low overnight (ULO) are on-peak, mid-peak, weekend off-peak, and ultra-low overnight.

1. On-peak reflects times when average *demand* is highest.
    a. The on-peak period is from 4 p.m. to 9 p.m. on weekdays, all year.
2. Mid-peak reflects the shoulder periods between on-peak and weekend off-peak times.
    a. The mid-peak period is from 7 a.m. to 4 p.m. and from 9 p.m. to 11 p.m. on weekdays, all year.
3. Weekend off-peak reflects times between 7 a.m. and 11 p.m. on weekends and holidays, all year.
4. Ultra-low overnight reflects times between 11 p.m. and 7 a.m., every day, all year.

Distributors must calculate the difference between the payments received from regulated *consumers* subject to RPP and the wholesale cost of power, including the amount of the Global Adjustment allocated to the RPP portion of a *distributor*'s load. Submissions by *distributors* to the IESO are processed as manual line items in *settlement statements* and monthly *invoices*. The IESO uses *charge type 142* "Regulated Price Plan Settlement Amount" for processing *distributor* submissions. RPP eligible *consumers* are defined by regulation.

Distributors that are *market participants* must submit the information to the IESO online noting the amount of the claim for each category. The settlement form available within Online IESO is used to submit all information required from the *distributor*, embedded *distributor* or participating *retailer* to balance the market. *Settlement* data must be submitted to the IESO monthly, as soon as possible after the last *trading day* of the month and no later than the 4th *business day* after the last *trading day* of the month. The IESO processes this information so that the *preliminary settlement statement* for the last *trading day* of the month indicates a *charge type* 142, with the category noted in the Comments field. If any changes are required to the amounts submitted during the preliminary submission period, final adjustments can be submitted during the 11th to 14th *business day* after the last *trading day* of the month. The adjustments will be reflected on the *final settlement statement* for the last *trading day* of the month. Furthermore, post final adjustments can be submitted through Online IESO for any previous settlement period. Any amount submitted as a post final adjustment will be settled on the *preliminary settlement statement* for the last *trading day* of the current settlement month.

[7] Summer and winter periods are as defined by the *OEB* and can be found on their website (Electricity rates | Ontario Energy Board (oeb.ca))

The IESO adjusts *settlement amounts* for directly *connected consumers* who are eligible for the RPP for the net volume of electricity withdrawn from the *IESO-controlled grid* not covered by *physical bilateral contracts*.

The corresponding setoff, *charge type* 192 "Regulated Price Plan Balancing Amount" is entered as manual line items on the IESO's *settlement statements* for the last *trading day* of the month to balance the market.

Declaration Required for Designated Consumers

"Regulations 435/02, 43/04 and 433/02" define 'designated *consumer*'. Wholesale *market participants* who qualify as 'designated *consumers*', must inform us by submitting the on-line form "Declaration of Designated Consumer" located on the *IESO* Gateway. *Market participants* who satisfy us that they qualify as designated *consumers* are settled at the RPP rate.

Opt-Out Provisions

Eligibility of *market participants* to opt out of the RPP is based on the following provision:

- directly-*connected* load-consuming *market participants* meeting the regulated definition of "low-volume *consumers*" or "designated *consumers*" may opt out of RPP for all *registered facilities* for which they play the role of a *metered market participant* provided the *facilities* have interval metering.

Market participants must inform us in writing if they wish to exercise this option.

1.6.7.8 Global Adjustment

We make adjustments to settlement amounts monthly to reflect the portion of the Global Adjustment allocated to each *market participant* with load in Ontario. The total Global Adjustment for a month is the sum of the charges shown below in Table 1.2.

For further certainty, and without otherwise affecting its interpretation, for the purposes of this section 1.6.7.8, references to load facilities, as defined in Ontario Regulation 429/04, includes the withdrawing component of *electricity storage facilities.*

Table 1–2: Global Adjustment Charge Types

Charge Type #	Charge Type Name
143	OEFC Adjustment Settlement Amount
144	Regulated Nuclear Generation Adjustment Amount
145	Regulated Hydroelectric Generation Adjustment Amount
1400	OPA Contract Adjustment Settlement Amount
1410	Renewable Energy Standard Offer Program Settlement Amount
1411	Clean Energy Standard Offer Program Settlement Amount
1412	Feed-In Tariff Program Settlement Amount
1414	Hydroelectric Contract Initiative Settlement Amount
1416	Conservation and Demand Management – Compensation Settlement Credit

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Charge Type #	Charge Type Name
1418	Biomass Non-Utility Generation Contracts Settlement Amount
1419	Energy from Waste (EFW) Contracts Settlement Amount
1421	Capacity Agreement Settlement Credit
1422	Capacity Agreement Penalty Settlement Amount
1423	Energy Sales Agreement Settlement Credit
1424	Energy Sales Agreement Penalty Settlement Amount
1425	Hydroelectric Standard Offer Program Settlement Amount

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Market Participant Load Facility Classification

Your portion of the Global Adjustment depends on the amount of load you withdraw from the *IESO controlled grid* at each of your load facilities, as defined in Ontario Regulation 429/04. There are two methods for the distribution of the Global Adjustment.

Method 1A - Class A Market Participant Load Facilities

Class A *Market Participant* Load Facilities are defined by the following criteria:

- The *market participant* is neither a licensed *distributor* nor a regulated *consumer.*
- The *market participant* was a *market participant* throughout the applicable Base Period.
- The load facility meets the definition of load facility in Ontario Regulation 429/04
- The total volume of electricity, as determined by the *IESO*, supplied by the *market participant* to the *IESO*-controlled grid or to the distribution systems of licensed *distributors* during the applicable Base Period did not exceed the total volume of electricity the *market participant* withdrew from the *IESO-controlled grid* or the distribution systems of licensed *distributors* during that Base Period.
- The maximum hourly demand[8] for electricity for each load facility, as defined in Ontario Regulation 429/04, in a month, determined independently, exceeds an average of 5 megawatts for the applicable Base Period.

Method 1B – Optional Class A Market Participant Load Facilities

For Adjustment Periods commencing on or after July 1, 2017, optional Class A *Market Participant* Load Facilities are defined by the following criteria:

- The market participant is neither a licensed distributor nor a regulated consumer.
- The market participant was a market participant throughout the applicable Base Period.
- The market participant elects to be a Class A market participant for the load facility for the applicable Adjustment Period, or has made such an election for a prior Adjustment Period and the election has not been revoked. Written notice of the election must be made to the IESO no later than June 15 of the calendar year in which the Adjustment Period begins.
- The load facility meets the definition of load facility in Ontario Regulation 429/04
- The total volume of electricity, as determined by the IESO, supplied by the market participant to the IESO-controlled grid or to the distribution systems of licensed distributors during the applicable Base Period did not exceed the total volume of electricity the market participant withdrew from the IESO-controlled grid or the distribution systems of licensed distributors during that Base Period.
- The maximum hourly demand for electricity for each load facility, as defined in Ontario Regulation 429/04, in a month, determined independently, exceeds an average of 1 megawatt but is less than or equal to an average of 5 megawatts for the applicable Base Period.

[8] Demand in these references refers to Allocated Quantity of Energy Withdrawn (AQEW) from the *IESO-controlled grid*.

Global Adjustment – Base and Adjustment Periods

There are two periods that relate to the eligibility and *settlement* of the Global Adjustment for Class A *Market Participant* Load Facilities. The Base Period is the period during which the load pattern of the *market participant* will determine potential Class A qualification. The Adjustment Period is the *settlement* period over which that Class A qualification will be applied. The Base Periods and related Adjustment Periods for 2012 and beyond are shown below:

Base Period	Adjustment Period
May 1, 2011 to April 30, 2012	July 1, 2012 to June 30, 2013
May 1, 2012 to April 30, 2013	July 1, 2013 to June 30, 2014
May 1, (Year X) to April 30, (Year X+1)	July 1, (Year X+1) to June 30, (Year X+2)

Method 2 - Class B Market Participant Load Facilities

All other *Market Participant* Load Facilities, as defined in Ontario Regulation 429/04, that consume electricity, excluding licensed *distributors*, are considered Class B load.

Exception

All registered load facilities, as defined in Ontario Regulation 429/04, associated with *market participants* that were deemed to be Class A in the May 1, 2011 to April 30, 2012 Base Period will be treated as Class A if the aggregated maximum hourly demand for electricity of all registered load facilities, as defined in Ontario Regulation 429/04, in a month exceeds an average of 5 megawatts in future Base Periods.

Opt Out

Market Participant Load Facilities, as defined in Ontario Regulation 429/04, eligible for Class A treatment based on the eligibility criteria noted above for any Base Period may elect to deem the load facility as Class B for the related Adjustment Period. This election must be made annually via written notice to the *IESO* on or before June 15th in any year.

Global Adjustment - Settlement

Class A Market Participant Load Facilities and Distributors with Class A Consumers

Class A *market participant* load facilities, as defined in Ontario Regulation 429/04, and *distributors* with Class A *consumers* will be apportioned their share of the total Global Adjustment amount each month in a defined Adjustment Period based on a "Peak Demand Factor" calculation based on their load pattern in the related Base Period.

The *IESO* will determine, for the appropriate Base Period, the five hours during which the greatest volume of electricity was dispatched through the *IESO-administered markets* for the purpose of supplying Ontario demand. The five peak hours shall occur on different days during the Base Period.

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The Ontario demand is defined as the Ontario generation dispatched into the *IESO-controlled grid* plus any imports, net of the following adjustments:

a) the total *energy* injected into the *IESO-controlled grid* from *generators* that have not submitted *offers*;

b) the total *energy* dispatched outside of Ontario from the *IESO-controlled grid*;

c) the total *energy* associated with off-market transactions such as the *segregated mode of operation*, emergency energy acquired or provided to meet system *reliability* needs, simultaneous activation of *operating reserve* and inadvertent interchange as a result of differences between scheduled and actual *intertie* flow; and

d) the total *energy* resulting from over or under generation in the event of differences during the balancing of supply and demand.

Ontario Demand = Total Energy + Total Generation Without Offers – Total Exports + Total Off Market +/- Over/Under Generation

The Peak Demand factor for a Class A *market participant* will be based on their consumption coincident with the five peak hours identified for the Base Period. The Peak Demand Factor will be calculated as follows:

$$\text{Peak Demand Factor} = \sum_{\text{Peak Hours}} \text{Coincident Class A Market Particpant Consumption} \div \sum_{\text{Peak Hours}} \text{Peak System Consumption}$$

Where the Peak System Consumption for the Peak Hour is the hourly Allocated Quantity of Energy Withdrawn (AQEW) from the *IESO-controlled grid*, net of several adjustments, including:

a) the net volume of *embedded generation offsetting* the *load* of licensed *distributors*;

b) the net volume of *energy* withdrawn at the Sir Adam Beck Pump Generating Station;

c) the net volume of *energy* withdrawn by Fort Frances Power Corporation under its *physical bilateral contract* with Abitibi-Consolidated Hydro Limited Partnership; and

d) the net volume of *energy* withdrawn by *market participants* in the course of providing *ancillary services* in accordance with the *market rules*.

The coincident peak consumption amounts for Class A *market participants* or for *distributors* with Class A *consumers* will be determined from AQEW values derived for *settlement* in the Base Period. *Distributors* will be asked to submit the amount of Class A *consumer* load coincident with peak hours at the end of the appropriate Base Period along with the *embedded generation* that has offset the load in their distribution territory coincident with the peak hours. Note:

- Injections to the *IESO-controlled grid* during the peak hours should not be included in the *distributor*'s *embedded generation* data submission to the *IESO*.
- *Distributors* are not required to provide the *IESO* with peak hour volumes for *generation facilities* that are eligible for net metering (Ontario Regulation 541/05) if that volume has offset the related load. If the volume is greater than the related load, the amount injected to the *distribution system* should be submitted to the *IESO*.

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- The submission includes *embedded generation* volumes for all non-contracted *generation facilities* and all contracted *generation facilities* (Renewable Energy Standard Offer Program, Hydroelectric Contract Initiative and Feed-In Tariff Program). The contracted *embedded generation* volumes are reported for the peak hour they are metered, regardless of the contract approval status.

The Global Adjustment assigned to a Class A *market participant* load facility, as defined in Ontario Regulation 429/04, or *distributors* with Class A *consumers* for a month in the Adjustment Period will be determined by multiplying the Peak Demand Factor by the total Global Adjustment for the month.

Class B Market Participant Load Facilities and Distributors

Class B *market participant* load facilities, as defined in Ontario Regulation 429/04, will be assigned a portion of the total Global Adjustment for any month based on the net volume of electricity withdrawn from the *IESO-controlled grid* for the month.

All *generators* will be considered Class B *market participant* load facilities, as defined in Ontario Regulation 429/04, when consuming electricity from the *IESO controlled grid*. Some *generators* that consume electricity either when providing *ancillary services* or for consumption related to the Beck Pump Generating Station will have this amount netted off their total consumption.

Distributors will be assigned a portion of the Global Adjustment based on the net volume of electricity withdrawn from the *IESO-controlled grid* for the month plus embedded generation that has offset the load in their territory less Class A *consumer* consumption in the month.

The *distributor* data submission to the *IESO* for each month includes embedded generation offsetting load, total embedded generation, Class A *consumer* consumption, and electricity storage injections/withdrawals. The data submission must be completed by the fourth *business day* after the month-end, using the" Embedded *Generation Energy Storage and Class A Load"* [9] form available within Online IESO. If any changes are required to the amounts submitted during the preliminary submission period, final adjustments can be submitted during the 11th to 14th *business day* after the last *trading day* of the month. The adjustments will be reflected on the *final settlement statement* for the last *trading day* of the month. Note:

- *Distributors* should not submit injections/generation or withdrawal/load from IESO *market participants*.
- The submission must include embedded generation volumes for all non-contracted *generation facilities* and all contracted *generation facilities* (Renewable Energy Standard Offer Program, Hydroelectric Contract Initiative and Feed-In Tariff Program). The contracted embedded generation volumes are reported for the month they are metered, regardless of the contract approval status.
- *Distributors* are not required to provide the *IESO* with volumes for *generation facilities* that are eligible for net metering (Ontario Regulation 541/05) if that volume has offset the related load. If the volume is greater than the related load, the amount injected to the *distribution system* should be submitted to the *IESO*. This applies to the submission of embedded generation offsetting load, total embedded generation and electricity storage injections/withdrawals.

[9] *Electricity storage participants* are to use the Embedded Generation Energy Storage and Class A Load form. The IESO will update the title of this form to include the term "Electricity" storage during further iterations of tool updates.

- Injections to the *IESO-controlled grid* should not be included in the *distributor*'s embedded generation offsetting load data submission to the *IESO*.

The total amount of Global Adjustment assigned to all Class B *market participants* and licensed *distributors* will exclude the Global Adjustment allocated to Class A *market participants* and licensed *distributors* with Class A *consumers*.

The total Class B consumption for the month will be calculated as follows:

$Total\ Class\ B\ Load = Total\ AQEW +$ Embedded Generation offsetting the load of licensed *distributors* - Beck Pump Generating Station AQEW - Fort Frances Power Corporation under its *physical bilateral contract* amount – AQEW related to providing *ancillary services* – AQEW of Class A *market participant load facilities* and LDC Class A *consumers*. –Electricity Storage Injections from *Class B market participant* and *consumer* electricity storage facilities.

Class B Rates

The *IESO* will be calculating and posting a Class B Global Adjustment rate for *distributors* to use in settling with their Class B *Consumers*. This rate will be published in a given month three times which are as follows:

1) First Estimate – Calculated on the last *business day* of the previous month.
2) Second Estimate – Calculated on the last *business day* of the month.
3) Actual Class B rate – Calculated on the 10th *business day* of the following month.

The estimated rates will be based on estimates of the Class B Global Adjustment amounts and Class B consumption. The final rate will be calculated based on actual values for the month.

Corrections from a prior period due to embedded generation or Class A load amounts will be recovered from the market using Class B current settlement month load quantities. Note, the prior period Class B load quantities relating to the period of correction are not being used for recovery.

The estimated Class B Global Adjustment amount and Class B Consumption will be calculated as shown below for the First Estimate.

Class B Global Adjustment Amount	Class B Consumption
Estimated Global Adjustment for the previous month (e.g. for March use estimate for February)	Estimated Load for the month
Plus/Minus corrections for the estimates used in previous month calculations	
Multiplied by [1- Total Peak Demand Factors for current Adjustment Period]	Plus Embedded Generation values used in the settlement of the month two months prior (e.g. estimate for March based on submission for January)
	Minus Class A Market Participant Load Facility and Consumer load used in the settlement of the month two months prior
	Minus Fort Frances load for the month

Class B Global Adjustment Amount	Class B Consumption
	Minus Sir Adam Beck PGS load used in the settlement of the month two months prior
	Minus Load associated with the provision of Ancillary Services used in the settlement of the month two months prior
	Minus Class B Market Participant and Consumer Electricity Storage Facility Injections used in the settlement of the month two months prior

The rate will be calculated (to the nearest cent) as:

Class B Global Adjustment Amount ÷ Class B Consumption

The estimated Class B Global Adjustment amount and Class B Consumption will be calculated as shown below for the Second Estimate.

Class B Global Adjustment Amount	Class B Consumption
Estimated Global Adjustment for the month	Estimated Load for the month
Plus/Minus Final Adjustment of previous months Global Adjustment	
Plus/Minus corrected Global Adjustment for prior periods (results from Global Adjustment distributions corrections related to revenue metering adjustments for prior periods)	Plus Embedded Generation values used in the settlement of the previous month
Multiplied by [1- Total Peak Demand Factors for current Adjustment Period]	Minus Class A Market Participant Load Facility and Consumer load used in the settlement of the previous month
	Minus Fort Frances load for the month.
	Minus Sir Adam Beck PGS load used in the settlement of the previous month.
	Minus Load associated with the provision of Ancillary Services used in the settlement of the previous month.
	Minus Class B Market Participant and Consumer Electricity Storage Facility Injections used in the settlement of the previous month

The rate will be calculated (to the nearest cent) as:

Class B Global Adjustment Amount ÷ Class B Consumption

The Class B Global Adjustment amount and Class B Consumption will be calculated as shown below for the Actual rate.

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Class B Global Adjustment Amount	Class B Consumption
Preliminary Global Adjustment for the month	Preliminary Settlement Load for the month
Plus/Minus Final Adjustment of previous months Global Adjustment	
Plus/Minus corrected Global Adjustment for prior periods (results from Global Adjustment distributions corrects ions related to revenue metering adjustments for prior periods)	Plus Embedded Generation values used in the settlement of the month
Multiplied by [1- Total Peak Demand Factors for current Adjustment Period]	Minus Class A Market Participant Load Facility and Consumer load used in the settlement of the month
	Minus Fort Frances load for the month
	Minus Sir Adam Beck PGS load used in the settlement of the month
	Minus Load associated with the provision of Ancillary Services used the settlement of the month.
	Minus Class B Market Participant and Consumer Electricity Storage Facility Injections used in the settlement of the month

The rate will be calculated (to the nearest cent) as:

Class B Global Adjustment Amount ÷ Class B Consumption

Electricity Storage Injection Reimbursement

As per Ontario Regulation O. Reg 516/17 (amending O. Reg 429/04), effective July 1, 2018, Class B *market participants* and *consumers* with *electricity* storage facilities are to be reimbursed Class B Global Adjustment amounts each month based on the amount of energy they inject into the IESO-controlled grid (for *market participants*) or the grid of their *distributor* (for *consumers*) in that month.

Distributors are compensated based on the volume of energy storage injections they report in the *Embedded Generation, Energy Storage, and Class A Load* form on Online IESO.

Class A Market Participant/Consumer Changes in the Adjustment Period

There are a number of potential situations that can impact the classification of Class A *consumers* and Class A *market participant* load facilities, as defined in Ontario Regulation 429/04, and their Global Adjustment treatment over the Adjustment Period.

1) Class A customer or load facility ceases operation.
2) Class A load facility moves either from being a *market participant* to a *distributor* customer or vice-versa.
3) A Class A load facility changes ownership.
4) A Class A load facility elects to become a Class B customer due to "Extraordinary Circumstances" under provisions set out in the regulation.

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In the event that any of these situations occur, the owner of the Class A load facility must inform the *IESO* or their licensed *distributor*. Depending on the situation the *distributor* must inform the *IESO*, or alternatively, the *IESO* must inform the *distributor*, as soon as possible so the proper treatment of the Global Adjustment can be determined.

Monthly Settlement

The *settlement amount* for *market participants* with eligible Class A load facilities, as defined in Ontario Regulation 429/04, or *distributors* with Class A *consumers* will be included on the *settlement statements* for the last *trading day* of the month under *charge type* 147 "Class A Global Adjustment Settlement Amount".

The *settlement amount* for Class B *market participants* or *distributors* will be included on the *settlement statements* for the last *trading day* of the month under *charge type* 148 "Class B Global Adjustment Settlement Amount".

Any prior period corrections for *charge type* 148 "Class B Global Adjustment Settlement Amount" resulting from post-final changes to input data (e.g. embedded generation, electricity storage or load quantities) for a settlement month prior to the *RSS commencement date* will be settled for the impacted *market participant* under *charge type* 2148 "Class B Global Adjustment Prior Period Correction Settlement Amount". In addition, post-final changes to input data impacting charge type 6148 "Class B Global Adjustment Deferral Recovery Amount" will be settled for the impacted *market participant* under charge type 6148. In turn, these corrective settlements will be balanced to the Class B market using Class B current settlement month load quantities.

The *settlement amount* relating to electricity storage injection reimbursement for Class B *market participants* or *distributors* will be included on the *settlement statement* for the last *trading day* of the month under *charge type* 1148 "GA Energy Storage Injection Reimbursement".

The corresponding set-offs are *charge type* 196 "Global Adjustment Balancing Amount" and *charge type* 197 "Global Adjustment - Special Programs Balancing Amount". *Charge type 196* is included on the IESO's *settlement statement* for the last *trading day* of the month. *Charge type* 197 is balanced by the *IESO* at the end of the month for special programs relating to conservation and demand management.

1.6.7.9 Intentionally Left Blank

Note:	The section 'OPA Administration Charge' has been removed. The OPA Administration Charge was last settled on the December 2016 settlement statements and invoice. For more details, refer to Appendix E.6, where the archived section can be found.

1.6.8 Limiting CMSC Payments for Exporters and Dispatchable Loads and Electricity Storage Participants

Exporters and *dispatchable loads* and dispatchable *electricity storage facilities* that withdraw may be eligible for CMSC payments from the marketplace when they submit negative bids and are *constrained on* by the *IESO*. To minimize uplift costs for Ontario *consumers*, the *IESO,* under Section 3.5.6A, Chapter 9 of the *market rules,* may adjust any bid price associated with an exporter or *dispatchable load facility* for calculating CMSC payments under the following conditions:

1. The bid price is less than the replacement bid prices determined by the *IESO* (i.e. -$125/MWh for exporters and -$15/MWh for *dispatchable loads*); and

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2. The bid price is less than the applicable *energy* market price (i.e. the zonal clearing price at the *intertie* for exporters or the Ontario market clearing price for *dispatchable loads*).

When these two conditions are met, the *IESO* may adjust the negative bid price to the *lesser* of the replacement bid prices determined by the *IESO* and the applicable *intertie* or Ontario market clearing price.

Exporters may submit a *notice of disagreement* and a suggested replacement price to recover their costs in cases where,

a) the negative bid is adjusted to the replacement bid price set by the *IESO* (i.e. -$125/MWh); and

b) the export transaction is settled in the neighbouring market at a negative price that is less than the replacement bid price set by the *IESO*; and

c) the total value of unrecovered costs (i.e. CMSC not paid due to the replacement bid) for the trade date that is the subject of the submitted *notice of disagreement* exceeds $1,000.

Dispatchable loads and dispatchable *electricity storage facilities* that withdraw may submit a *notice of disagreement* for any trade date in a month where,

a) the combined preliminary hourly and daily uplifts for a trade date reported on the *IESO* website exceeds $2.50/MWh; and

b) the negative bid is adjusted to the replacement bid price set by the *IESO* (i.e. -$15/MWh); and

c) the total value of unrecovered costs (i.e. CMSC not paid due to the replacement bid) for the trade date that is the subject of the submitted *notice of disagreement* exceeds $1,000.

The *notice of disagreement* should provide details of the transaction including evidence to support the suggested replacement price and the value of the requested compensation.

1.6.9 Adjustment for Facility-Induced CMSC

Under Section 3.5.1A of Chapter 9 of the *market rules,* a *market participant* is not entitled to congestion management *settlement* credits (CMSC) where these are the result of the *facility's* own equipment or operational limitations under certain circumstances. Such situations include a *dispatchable load facility* or a dispatchable *electricity storage facility* that withdraws which does not fully or accurately respond to *dispatch instructions* or where the bid ramp rate is below the specified threshold. The *market rules* enable us to:

- avoid making the CMSC payments entirely; or
- completely recover such payments after the fact from the *dispatchable load* or dispatchable *electricity storage facility* that withdraws.

This procedure describing recovery of deviation-induced CMSC also applies when the *dispatchable load* has a bid price equal to the *maximum market clearing price* (*MMCP*). With respect to *dispatchable loads* in particular, not only is a *dispatch* deviation the likely cause of the *dispatch*, but according to Section 3.3.18 of Chapter 7 of the *market rules,* this price indicates the load is to be treated as *non-dispatchable* and, therefore, it is not eligible for CMSC. In addition, and for further certainty, a *market participant* registered as an *electricity storage facility* is not entitled to change its load status as per Market Manual 4: Market Operations, Part 4.2: Submission of Dispatch Data in the Real-Time Energy and Operating Reserve Markets, section 2.4.1.

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1.6.9.1 Assessment

The following business rules identify the criteria we use when recovering constrained-off CMSC paid to *dispatchable load facilities* or *electricity storage facilities* that withdraw.

- Business Rule 1 – Materiality

  Constrained-off CMSC is allowed for an interval if the total amount of CMSC paid during that *trading day* to that *dispatchable load* or *electricity storage facility* that withdraws is less than a specified threshold. The daily total includes negative CMSC. The threshold is currently set at $0 removing any exemptions and which replaces the previously set threshold of $4000.

- Business Rule 2 – *Non-Dispatchable* Portion of Load

  Constrained-off CMSC is not allowed for an interval if it is paid for portions of the schedule where the load has *bid +MMCP*, indicating that it is *non-dispatchable* in that range. This business rule applies unless CMSC is allowed because of materiality (Business Rule 1).

- Business Rule 3 – *Dispatch* Deviation

  Constrained-off CMSC is not allowed for an interval if the current 5-minute constrained schedule exceeds the *revenue meter* value in the previous interval plus 2.5 minutes of ramping. This business rule will be applied unless CMSC is allowed because:

- of materiality (Business Rule 1); or
- the load or dispatchable *electricity storage facility* that withdraws has been constrained-off economically (see Definition 1 below); or
- *operating reserve* has been activated (see Definition 2 below); or
- the load or dispatchable *electricity storage facility* that withdraws is ramping (see Definition 3 below); or
- the load or dispatchable *electricity storage facility* that withdraws has been manually dispatched down for *reliability* (see Definition 4).

- Business Rule 4 – *Facility* Off-Line or Unable to Follow *Dispatch Instructions*

  Constrained-off CMSC is not allowed for an interval if the constrained schedule is 0 MW and consumption is less than 1 MW, or if consumption is 0 MW. This business rule will be applied unless CMSC is allowed because:

- of materiality (Business Rule 1); or
- the load or dispatchable *electricity storage facility* that withdraws has been constrained-off economically (see Definition 1); or
- *operating reserve* has been activated (see Definition 2); or
- the load or dispatchable *electricity storage facility* that withdraws has been manually dispatched down for *reliability* (see Definition 4).

The business rules are supported by the following definitions:

- Definition 0 – *constrained off event*.

  A *constrained off event* comprises one or more consecutive intervals where:

- *market schedule* > constrained schedule; and
- *market schedule* > AQEW.

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- Definition 1 – economically *constrained off*

  A *dispatchable load* or a dispatchable *electricity storage facility* that withdraws is considered to be 'economically constrained-off' in an interval if the relevant nodal price is greater than or equal to the *bid* price for either the current interval, the next interval or the previous interval. The inequality is applied to the last MW constrained-off.

- Definition 2 – *operating reserve* activation (ORA)

  A *dispatchable load* or a dispatchable *electricity storage facility* that withdraws is considered to be *dispatched* in an interval as part of an activation of *operating reserve* if:

- its constrained schedule is labelled with the reason code 'ORA'; or
- the interval is 1-3 intervals in advance of an interval where its schedule is labelled with the 'ORA' code; or
- the interval is 1-3 intervals after an interval where its schedule is labelled with the 'ORA' code.

- Definition 3 – ramping

  A *dispatchable load* or a dispatchable *electricity storage facility* that withdraws is considered to be 'ramping' in an interval if it is one of the first 3 intervals of the second hour when ramping-up, or if it is one of the last 3 intervals of the first hour when ramping down. A *generation unit* is considered to be ramping up or ramping down in an hour when the unconstrained schedule differs between consecutive hours.

- Definition 4 – manually *constrained off* for *reliability*

  A *dispatchable load* or a dispatchable *electricity storage facility* that withdraws is considered to be 'manually *constrained off* for *reliability*' if our control room logs indicate that we needed to constrain off the load for system or local requirements.

1.6.9.2 Limiting Constrained Off CMSC for Dispatchable Loads and Dispatchable Electricity Storage Facilities that Withdraw

If you are the *market participant* for a *dispatchable load* or a dispatchable *electricity storage facility* that withdraws, you are <u>not</u> entitled to *constrained off* CMSC payments related to ramping, if you change your operating behavior as a result of conditions and/or actions at your *dispatchable load facility* or dispatchable *electricity storage facility* that withdraws, and not due to conditions on the *IESO-controlled grid*. Under sections 3.5.1D and 3.5.2, Chapter 9 of the *market rules*, the withholding of *constrained off* CMSC payments is limited to *bid* changes that result in changes to the *facility*'s *market schedule* and targets *constrained off* CMSC that is as a result of the *dispatchable load* or dispatchable *electricity storage facility* that withdraws ramping up or down.

The decision rules for ramping up or down are as follows:

A *dispatchable load* or a dispatchable *electricity storage facility* that withdraws is considered to be ramping down if:

i. There is a decrease in the constrained schedule between interval 9 and 12 of the current hour; and
ii. The unconstrained schedule in interval 12 of the current hour is greater than the unconstrained schedule in interval 1 of the next hour; and
iii. There is a change in the *bid* lamination between the current and the next hour.

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A *dispatchable load* or a dispatchable *electricity storage facility* that withdraws is considered to be ramping up if:

i. There is an increase in the constrained schedule between interval 12 of the previous hour and interval 3 of the current hour; and
ii. The unconstrained schedule in interval 12 of the previous hour is less than the unconstrained schedule in interval 1 of the current hour; and
iii. There is a change in the *bid* lamination between the previous and next hour.

These rules apply unless CMSC is allowed for the hour because of:

- Materiality (defined in Section 1.6.9.1 by 'Business Rule 1 – Materiality'); or
- The load has been *constrained off* economically in an interval (defined in Section 1.6.9.1 by Business Rule 4, 'Definition 1 – economically constrained off'); or
- *Operating reserve* has been activated (defined in Section 1.6.9.1 by Business Rule 4, 'Definition 2 – *operating reserve* activation'); or
- The load has been manually dispatched down for *reliability* (defined in Section 1.6.9.1 by Business Rule 4, 'Definition 4 – manually constrained off for *reliability*').

Under section 3.5.1D Chapter 9 of the *market rules*, for *trading days* on or after the *RSS commencement date*, the *IESO* will recover *constrained off* CMSC payment related to ramping of *dispatchable loads* or dispatchable *electricity storage facilities* that withdraw through *charge type* 105. The business rules in Section 1.6.9.1 and this section will continue to recover *constrained off* CMSC on an interval basis with the modified *settlement amount* appearing on the *settlement statement* for that *trading day*.

1.6.9.3 Adjustment for Self-Induced CMSC Earned for Dispatchable Loads or Dispatchable Electricity Storage Facility that Can Withdraw

Self-induced CMSC payments, also considered inappropriate, occur as the result of actions taken by a *dispatchable load facility* or a *dispatchable electricity storage facility* that can withdraw, and/or conditions at, or involving, a *dispatchable load facility* or a *dispatchable electricity storage facility* that can withdraw, and not by conditions on the *IESO-controlled grid*. If you are the *market participant* for a *dispatchable load facility* or a *dispatchable electricity storage facility* that can withdraw, the *IESO* may recover inappropriate CMSC payments from the *dispatchable loads* or the *dispatchable electricity storage facility* that can withdraw under the following scenarios, in accordance with section 3.5.6G of Chapter 9 of the *market rules*:

- A *dispatchable load facility* or a *dispatchable electricity storage facility* that can withdraw that either:
  i. is unable to follow *IESO dispatch instructions* for safety, legal, regulatory, environmental or equipment damage reasons; and/or
  ii. is constrained on or constrained off by the *IESO*, at the request of the *dispatchable load facility* or the *dispatchable electricity storage facility* that can withdraw for safety, legal, regulatory, environmental or equipment damage reasons.

CMSC earned by the *dispatchable load facility* or the *dispatchable electricity storage facility* that can withdraw in these scenarios is considered inappropriate as these payments are not consistent with the original intent of CMSC.

IESO staff will investigate these instances on an on-going basis and will notify the *market participant* for a *dispatchable load facility* or a *dispatchable electricity storage facility* that can withdraw of the

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applicable CMSC recovery. A *market participant* for a *dispatchable load facility* or a *dispatchable electricity storage facility* that can withdraw will have 5 *business days* to respond to the *IESO's* notification if the *market participant* disagrees. If the *market participant* does not respond within 5 *business days*, the CMSC included in the *IESO's* notice shall be recovered.

The CMSC recovery is applied as a manual entry to *charge type* 124 "SEAL Congestion Management Settlement Credit Amount" on your *settlement statement* for the last *trading day* of the month. The adjustment is rebated back to *market participants* as a single manual entry to *charge type* 155 "Congestion Management Settlement Uplift" on the *settlement statement* for the last *trading day* of the month.

1.6.10 Real-time Import Failure Charges and Export Failure Charges

The *market rules* no longer treat *intertie* transaction failures as solely a compliance matter. You will be assessed a *settlement* charge for import and export failures to compensate the market for *intertie* transaction failures that fail for reasons that are within your control, i.e., not "bona fide and legitimate". The *market rules* allow for compliance actions which may include both imposing a financial penalty or recovering any *settlement amounts* (such as *transmission rights* payments, congestion management *settlement* credits or other *settlement amounts*) that were inappropriately gained or avoided by a *market participant.* When *intertie* transaction failures are for bona fide and legitimate reasons, you are exempt from failure charges.

The Day-Ahead Commitment Process (DACP) includes a day-ahead import failure *settlement* charge (DA-IFC), a day-ahead export failure charge (DA-EFC) and a day-ahead linked wheel failure charge (DA-LWFC). Refer to "Market Manual 9: Part 9.5 Settlement of the DACP" for details on the DA-IFC, DA-EFC and DA-LWFC, and Chapter 7, Section 7.5.8B and Chapter 9, Sections 3.8B, 3.9 and 4.8 of the *market rules*.

1.6.10.1 Intertie Transaction Reason Codes and Resultant Settlement Treatment

When we manually alter an import or export schedule, we apply one of seven 'reason codes' to apply the appropriate *settlement* treatment. These reason codes are defined in Table 3–5 of the *IESO* Technical Interface document "Format Specifications for Settlement Statement Files and Data Files" (IMP_SPEC_0005). Refer to "Market Manual 4: Market Operations, Part 4.3: Real-time Scheduling of the Physical Markets" for more information regarding the application of reason codes to import and export schedules.

Table 1–3 contains the reason codes and the resulting treatment of CMSC, the day-ahead and real-time failure charges and day-ahead IOG.

For failed imports and exports:

- "Yes" indicates a failure meeting the criteria of a bona fide and legitimate reason for failure as described in Chapter 7, Section 7.5.8B in the *market rules* allowing the transaction to be exempt from the failure charge; and
- "No" indicates a failure not meeting the criteria of a bona fide and legitimate reason as described in the *IESO market rules*, exposing the transaction to the failure charge.

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Table 1–3: Failure Reason Codes and Settlement Treatment

Code Entered	DSO[10] Treatment	CMSC Treatment	DA IFC Exempt (Import)	DA EFC Exempt (Export)	DA LWFC Exempt	RT IFC Exempt (Import)	RT EFC Exempt (Export)	DA-IOG Component #2
OTH	Constrained Schedule equal to Market Schedule	No	No	No	No	No	No	No
TLRe	Constrained Schedule equal to Market Schedule	No	Yes	Yes	Yes	Yes	Yes	No
TLRi	Constrained Schedule not necessarily equal to Market Schedule	Yes or No based on DSO schedules	Yes	Yes	N/A	Yes	Yes	Yes
ORA	Constrained Schedule not necessarily equal to Market Schedule	Yes or No based on DSO schedules	Yes or No based on RT Offer Price Test (1)	Yes or No based on RT Offer Price Test(1)	N/A	N/A	Yes	Yes
MrNh	Constrained Schedule equal to Market Schedule	No	No	No	N/A	Yes	Yes	No
ADQH	Constrained Schedule equal to Market Schedule	No	Yes or No based on RT Offer Price Test(1)	Yes or No based on RT Offer Price Test (1)	N/A	Yes	Yes	Yes
NY90	Constrained Schedule not necessarily equal to Market Schedule	Yes or No based on DSO schedule	Yes or No based on RT Offer Price Test (1)	Yes or No based on RT Offer Price Test (1)	N/A	N/A	N/A	Yes
AUTO	Constrained Schedule not necessarily equal to Market Schedule	Yes or No based on DSO schedule	Yes or No based on RT Offer Price Test (1)	Yes or No based on RT Offer Price Test (1)	Yes or No based on RT Offer Price Test (1)	N/A	N/A	Yes

(1) RT Offer Price Test: IF DA Import Scheduled quantity is offered in RT at –MMCP then DA-IFC, DA-EFC is exempt.

Characteristics of the real-time import and *real-time export* failure charges include the following.

[10] DSO = Dispatch Scheduling and Optimization

1. RT import failure charges and RT export failure charges apply to all import/export transactions on all *IESO* interfaces that fail between hour-ahead pre-*dispatch* and real-time. The intertie failure charge is limited, in the case of imports, to the Ontario real-time *energy market price*, and in the case of exports, to the pre-*dispatch* Ontario price. The import failure charge is the mirror image of the export failure charge.
2. The import transaction may be exempted from these failure charges if we determine or you demonstrate that the failure of the day-ahead import transaction to flow in real-time is caused by bona fide and legitimate reasons. Generally, these reasons for import failure are beyond your control or due to our errors or actions or those of an external system operator. These reasons may be determined by our operations, or you can submit them to us for assessment through the *notice of disagreement* (NOD) process. Refer to Section 1.5.
3. We calculate the real-time import failure charge to a maximum import charge capped at a value proportional to the Ontario Market Clearing price for the interval. It is triggered when the adjusted real-time price is greater that the pre-*dispatch* price during the hour of failure.
4. We calculate the real-time export failure charge to a maximum export charge capped at a value proportional to the pre-*dispatch* Ontario price for the hour. It is triggered when the adjusted real-time price is less than the pre-*dispatch* price during the hour of failure.
5. We calculate an hourly applicable price bias adjustment factor used in both the real-time import and export failure charges. The price bias adjustment factor compensates for systematic differences between the pre-*dispatch* and real-time price. For example, there are systematic differences between the pre-*dispatch* and real-time price as a result of using Ontario *demand* forecast peak in PD versus the average in real-time price calculations. See Appendix D for a description of the methodology we use to calculate the bias adjustment factor.

For example:

Real-time Import Failure Charge: = Min [Max[0, ((RT Ont MCP + Import Bias Adjustment factor) – PD Ont MCP) * MWh deviation], Max (0, RT Ont MCP) * MWh deviation]

Real-time Export Failure Charge: = Min[Max[0, ((PD Ont MCP – RT Ont MCP – Export Bias Adjustment factor) * MWh deviation], Max (0, PD Ont MCP) * MWh deviation]

Example 1: PD price = $100
RT price = $120
Adjustment factor = $5
Volume failed = 100 MW

RT Import Failure Charge = minimum of [$120+$5-$100]*100 MW or ($25*100 MW)
= $2500

Example 2: PD price = $100
RT price = $80
Adjustment factor = $5
Volume failed = 100 MW

RT Export Failure Charge = minimum of [$100–$80–$5]*100 MW or ($100*100 MW)
= $1500

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6. The *settlement amount* is only payable from you to the *IESO-administered markets*. Payments of these *settlement amounts* to you under any other circumstances are not allowed. These *settlement amounts* are administered under *charge types* 135 "Real-time Import Failure Charge" and 136 "Real-time Export Failure Charge".
7. We distribute *settlement amounts* collected under these charges on a pro-rata basis to *market participants* with allocated quantities of *energy* withdrawn (AQEW, including export transactions) at the time for which the charge was assessed. This is distributed as a new component of *hourly uplift* in *charge type* 186 "Intertie Failure Charge Rebate". Refer to Chapter 9, Sections 3.9 and 4.8 of the *market rules*.
8. The *intertie* failure charge rebate is a new *charge type* that submits a new component of *hourly uplift* for distribution to the market. It distributes proceeds from the RT import failure charge (RT-IFC), the RT export failure charge (RT-EFC) and the DA import failure charge (DA-IFC) (net of any reductions for the *intertie* failure charge reversal (IFC-REV)).
9. This *hourly uplift* can be transferred as part of a *physical bilateral contract*. Refer to "Market Manual 5, Settlements, Part 5.3: Submission of Physical Bilateral Contact Data".

1.6.11 Standard Offer Program (SOP)

1.6.11.1 Renewable Energy Standard Offer Program (RESOP)

The OPA, as predecessor to the IESO, and *Ontario Energy Board* (*OEB*) developed a Renewable Energy Standard Offer Program (RESOP) for small *generators* that use renewable resources. These *generators connect* to electricity *distribution systems* at *distribution* voltages (50kV or less). Standard offer program projects have a maximum size of 10 megawatts (MW), and may include any renewable resource type that qualifies as a renewable resource in the Renewable Energy Supply II RFP including wind, small hydro-electric, solar, and some bio-mass. No minimum project size was proposed.

As of October 1, 2009, the RESOP was replaced by the Feed-in Tariff (FIT) Program) under the Green Energy Act[11]. New renewable *energy* supply projects will come under the umbrella of the new FIT Program and the *IESO* will no longer accept new RESOP applications. Projects that have already been approved under RESOP will continue according to their contracts. The terms and conditions of executed contracts, including the rates, will be unaffected by the new FIT Program.

This section sets out how the *IESO* settles the RESOP. To the extent of any inconsistency between the provisions of the RESOP rules and this section, the RESOP rules shall govern.

The Standard Offer Program provides a "standard price" which eligible *generators* receive by simply complying with the eligibility criteria. Contract terms are typically for 20 years. For the first year of commercial operation, all eligible renewable resource type projects (except solar photovoltaic) will be paid a base rate of 11.13 cents per kilowatt hour for all kilowatt hours delivered. Projects that can demonstrate *generation* control are eligible for an additional 3.52 cents per kilowatt hour for all electricity delivered during on-peak hours. For solar photovoltaic projects, a price of 42 cents per kilowatt hour is established to conduct price discovery on this technology.

[11] The Green Energy Act was introduced in the Ontario Legislature on February 23, 2009.

Under the Standard Offer Program, *generators* are paid directly for every kilowatt hour of electricity produced at the price set out in their standard offer contract. *Distributors* must calculate the difference between the contracted payments to standard offer program participants and the wholesale *market price* for the same volume of electricity. *Distributors* submit this difference to us monthly via the settlement form available within Online IESO noting the amount of the claim for each category. Information required from both the *distributor* and embedded *distributor* is submitted via the settlement form available within Online IESO.

Submit Standard Offer Program claims to us monthly as soon as possible after the last *trading day* of the month and no later than the fourth *business day* after the last *trading day* of the month. This submission is made using the settlement form "Renewable Energy Standard Offer Program" available within Online IESO. We process this information as a manual line item so that the *settlement statements* for the last *trading day* of the month and monthly *invoices* indicates a *charge type* 1410 "Renewable Energy Standard Offer Program Settlement Amount" with the category noted in the comment field. If any changes are required to the amounts submitted during the preliminary submission period, final adjustments can be submitted during the 11th to 14th *business day* after the last *trading day* of the month. The adjustments will be reflected on the *final settlement statement* for the last *trading day* of the month. Furthermore, post final adjustments can be submitted through Online IESO for any previous settlement period. Any amount submitted as a post final adjustment will be settled on the *preliminary settlement statement* for the last *trading day* of the current settlement month.

The corresponding setoff, *charge type* 1460 "Renewable Energy Standard Offer Program Balancing Amount", is entered as a manual line item on the IESO's *settlement statements* for the last *trading day* of the month to balance the market.

1.6.11.2 Feed-in Tariff Program (FIT)

The IESO has entered into procurement contracts under the Feed-in Tariff (FIT) Program with certain suppliers to encourage renewable *generation* to participate in a variety of technologies and their respective applications. The FIT Program will support renewable *energy* generating alternatives including wind, biomass, small hydro and solar photovoltaic. For suppliers that are directly *connected* to the *IESO-controlled grid*, the *IESO* will settle these contracts directly. For suppliers (i.e., *generators*) embedded within a *distribution system*, the *distributors* will settle these contracts with the *embedded generators*.

This section sets out how the *IESO* settles the FIT Program. To the extent of any inconsistency between the provisions of the FIT Program Rules and this section, the FIT Program Rules shall govern.

Distributors must calculate the difference between the amount paid to the supplier for electricity produced calculated at wholesale *market prices*, and the amount calculated at the contract price. The adjustment can be either positive or negative, charged or paid to the *distributors* who will settle the contracts with the individual suppliers. *Distributors* submit this difference to us monthly via the settlement form "Feed-in Tariff Program" available within Online IESO.

Submit FIT Program claims to us monthly as soon as possible after the last *trading day* of the month and no later than the fourth *business day* after the last *trading day* of the month. This submission is made using the settlement form "Feed-in Tariff Program" accessible via Online IESO. We process the information as a manual line item so that the *settlement statements* for the last *trading day* of the month and monthly *invoices* indicates a *charge type* 1412 "Feed-in Tariff Program Settlement Amount" with the category noted in the comment field. If any changes are required to the amounts submitted during the preliminary submission period, final adjustments can be submitted during the 11th to 14th *business day* after the last *trading day* of the month. The adjustments will be reflected on

the *final settlement statement* for the last *trading day* of the month. Furthermore, post final adjustments can be submitted through Online IESO for any previous settlement period. Any amount submitted as a post final adjustment will be settled on the *preliminary settlement statement* for the last *trading day* of the current settlement month.

The corresponding setoff, *charge type* 1462 "Feed-in Tariff Program Balancing Amount", is entered as a manual line item on the IESO's *settlement statements* for the last *trading day* of the month to balance the market.

1.6.11.3 Hydroelectric Contract Initiative (HCI)

The IESO has entered into procurement contracts under the Hydroelectric Contract Initiative (HCI) with qualified existing hydroelectric *generation facilities* to increase Ontario's supply of clean, renewable *generation*. The HCI supports new contracts for hydroelectric *facilities* that are *connected* to the *IESO-controlled grid* but not owned by OPG. For large *facilities* (generally ≥ 10 MW) that are directly *connected* to the *IESO-controlled grid*, the *IESO* will settle these contracts directly. For small *facilities* (generally < 10 MW) embedded within a *distribution system*, the *distributors* will settle these contracts with the participating *embedded generators*.

This section sets out how the *IESO* settles the HCI. To the extent of any inconsistency between the provisions of the HCI rules and this section, the HCI rules shall govern.

Distributors must calculate the difference between the amount paid to the participating *embedded generators* for electricity produced calculated at wholesale *market prices*, and the amount calculated at the contract price. The adjustment can be either positive or negative, charged or paid to the *distributors* who will settle the contracts with the individual *generators*. If you are a *distributor* who has a participating *generation facility*, please contact *IESO* Customer Relations for instructions on submitting HCI claims at: customer.relations@ieso.ca.

Submit HCI claims to us monthly as soon as possible after the last *trading day* of the month and no later than the fourth *business day* after the last *trading day* of the month. This submission is made using the settlement form "Hydroelectric Contract Initiative" available within Online IESO. We process the information as a manual line item so that the *settlement statements* for the last *trading day* of the month and monthly *invoices* indicate a *charge type* 1414 "Hydroelectric Contract Initiative Settlement Amount". If any changes are required to the amounts submitted during the preliminary submission period, final adjustments can be submitted during the 11th to 14th *business day* after the last *trading day* of the month. The adjustments will be reflected on the *final settlement statement* for the last *trading day* of the month. Furthermore, post final adjustments can be submitted through Online IESO for any previous settlement period. Any amount submitted as a post final adjustment will be settled on the *preliminary settlement statement* for the last *trading day* of the current settlement month.

The corresponding setoff, *charge type* 1464 "Hydroelectric Contract Initiative Balancing Amount", is entered as a manual line item on the IESO's *settlement statements* for the last *trading day* of the month to balance the market.

1.6.11.4 Hydroelectric Standard Offer Program

The IESO has entered into agreements under the Hydroelectric Standard Offer Program (HESOP) to support the continued development of hydroelectric capacity in Ontario. Procurements under HESOP have concluded. The HESOP program has been developed in two separate streams:

- Municipal Stream: new-build waterpower projects larger than 500 kilowatts (kW) that were the subject of an application to the Feed-in Tariff Program submitted before June 5, 2010.

- Expansion Stream: incremental hydroelectric capacity projects at non-utility generation (NUG) facilities under contract with the Ontario Electricity Financial Corporation, and incremental hydroelectric capacity projects at facilities under contract with the IESO as part of the Hydroelectric Contract Initiative (HCI).

Submit HESOP claims to us monthly via Online IESO as soon as possible after the last *trading day* of the month and no later than the fourth *business day* after the last *trading day* of the month. We process the information as a manual line item so that the *settlement statements* for the last *trading day* of the month and monthly *invoices* indicate a *charge type* 1425 "Hydroelectric Standard Offer Program Settlement Amount". If any changes are required to the amounts submitted during the preliminary submission period, final adjustments can be submitted during the 11th to 14th *business day* after the last *trading day* of the month. The adjustments will be reflected on the *final settlement statement* for the last *trading day* of the month. Furthermore, post final adjustments can be submitted through Online IESO for any previous settlement period. Any amount submitted as a post final adjustment will be settled on the *preliminary settlement statement* for the last *trading day* of the current settlement month.

The corresponding setoff, *charge type* 1475 "Hydroelectric Standard Offer Program Balancing Amount", is entered as a manual line item on the IESO's *settlement statements* for the last *trading day* of the month to balance the market.

1.6.12 CMSC Adjustment for Replacement Offer Events

Generators who experience a *forced outage* at a hydroelectric *generation facility* or who experience a *forced outage* of a gas turbine at a combined cycle *generation facility*, an *enhanced combined cycle facility*, or a *cogeneration facility* are allowed to submit revised *dispatch data* for a related *generation facility*. We expect to receive revised *dispatch data* for the next *dispatch hour*. In some instances, the revised *dispatch data* will not be effective until the subsequent *dispatch hour* if the *forced outage* occurs too near the end of the current *dispatch hour* to meet timelines for *dispatch data* submission.

In the interim period before the revised *dispatch data* is processed by market systems, we must accept the replacement *energy* from the related *generation facility* for the *facility* that has been forced out, provided there is no adverse impact on the *reliability* of the *IESO-controlled grid*. The replacement *energy* is limited to the original *energy* as scheduled for the *facility* experiencing the *forced outage*.

Any congestion management *settlement* credit payments to the related *generation facility* during the interim period will be limited to an estimate of what would have been received by the *generation facility* experiencing the *forced outage*[12].We take the following steps in estimating the amount of CMSC that would have been received by the *facility* experiencing the *forced outage* and in applying the CMSC adjustments during a replacement offer event.

- Determine the 'reference interval'.

  The reference interval is the interval during a replacement offer event immediately before the interval where:

  - the *market schedule* or the constrained schedule declines in response to the failure of the original *generation facility*; or
  - the related *generation facility* is constrained on,

  whichever comes first.
- Determine the 'CMSC limit'.

[12] See Chapter 9, Sections 3.5 and 4.8 of the *market rules*

The CMSC limit is the total CMSC paid to the original *generation facility* and the related *generation facility* during the reference interval.

- Determine the 'End of the replacement offers period'.

  The replacement offers period ends when the market tools process the revised *dispatch data*. Typically, we expect this to be at the end of the current *dispatch hour*. In some instances, the *forced outage* occurs too near the end of the current hour to allow new *offers* to be submitted, and the replacement offers period will extend to the end of the next *dispatch hour*.

- Determine the 'CMSC paid'.

  The CMSC paid includes the amount of CMSC paid to the original *generation facility* and the amount paid to the related *generation facility* during each interval from the first interval after the reference interval until the end of the replacement offers period.

- Calculate and apply the CMSC adjustment.

  The CMSC adjustment in each interval is the difference between the 'CMSC paid' and 'CMSC limit' during the replacement offer event according to:

  CMSC (adj) = Min (0, - (CMSC paid – CMSC limit))

  a) when 'CMSC paid' > 'CMSC limit', then the difference is clawed back;

  b) when 'CMSC limit' > 'CMSC paid', then the CMSC adjustment is zero and no entry appears on your *settlement statement*.

The adjustment is applied to *charge type* 105 "Congestion Management Settlement Credit for Energy" for each applicable interval of the replacement resource. The adjustment is rebated back to *market participants* as a single manual entry to *charge type* 155 "Congestion Management Settlement Uplift" for each replacement offer event.

1.6.13 Compensation Resulting from an SPS Activation

If you are a *market participant* with a *dispatchable generation facility* or dispatchable *electricity storage facility* that is not a *quick start facility* and that is part of a *Special Protection System (SPS)*, you may apply to the *IESO* for compensation if that *facility* is tripped offline as a result of the activation of the *SPS*.

The amount of compensation that may be claimed is the equivalent of up to the first two hours of constrained off congestion management *settlement* credit payments that would otherwise be calculated if the *facility* had been constrained down to zero and its circuit breaker had remained closed.

We calculate an *SPS* compensation amount for up to 24 intervals starting with the interval in which your *generation facility* was tripped offline. We will perform a CMSC-like calculation for each interval of the 24 consecutive compensation intervals using the *market schedule* set to the value in the interval preceeding the trip and the constrained schedule set to 0 MW. We will take into account any CMSC that was already paid (or charged in the case of negative CMSC) during the compensation period.

To apply for compensation if your *generation facility* is tripped offline following an *SPS* activation, submit your claim by email directly to customer.relations@ieso.ca.

1.6.14 Northern Energy Advantage Program (NEAP)

The Ministry of Northern Development, Mines, Natural Resources and Forestry (NDMNRF) has created and administers the Northern Energy Advantage Program (NEAP) to assist Northern

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Ontario's largest industrial electricity *consumers* by providing a rebate incentive for the development and implementation of long term efficiency and sustainability measures.

NEAP is a rebate incentive program which will be paid quarterly at a rate of $20/MWh for electricity consumed and individual rebates are capped at 2017 to 2020 average consumption levels, subject to the terms and conditions of the program rules and the NEAP funding agreements between the NDMNRF and the participant. The program rules, as amended from time to time, apply to the NEAP, previously known as the Northern Industrial Electricity Rate Program (NIERP), effective April 1, 2022.

The *IESO* is contracted by NDMNRF to provide *settlement* services. We use *charge type* 121 "Northern Energy Advantage Program Settlement Amount" for the NEAP payments to participants and we recover NEAP payments from the NDMNRF through *charge type* 171 "Northern Energy Advantage Program Balancing Amount"[13].

Refer to the NEAP program rules for eligibility requirements and payment conditions available on the NDMNRF website at:

https://www.ontario.ca/page/northern-energy-advantage-program

1.6.15 Intentionally Left Blank

Note: The section 'OPA's Demand Response (DR3) Program' has been removed. The DR3 program was last settled on the April 2015 settlement statements and invoice. For more details, refer to Appendix E.3, where the archived section can be found.

1.6.16 Intentionally Left Blank

Note: The section 'OPA's Demand Response (DR2) Program' has been removed. The DR2 program was last settled on the February 2015 settlement statements and invoice. For more details, refer to Appendix E.4, where the archived section can be found.

1.6.17 Conservation Assessment Recovery

The *IESO* is introducing a "Conservation Assessment Recovery" charge as a result of a recent Ontario government regulation. The regulation allows the *IESO* to recover the amount it is assessed with respect to the expenses incurred and expenditures made by the Ministry of Energy and Infrastructure for its *energy* conservation and renewable *energy* programs. The assessed amount shall be recovered in three payments on the month-end *settlements* for April, May and June 2010 from non-local distribution company (non-LDC) loads.

We are collecting the assessed amount through *charge type* 1415 "Conservation Assessment Recovery". The amounts charged to each affected *market participant* will be pro-rated based on their total Allocated Quantity of Energy Withdrawn (AQEW) for 2009 and the AQEW of all affected *market participants*.

[13] Refer to "IESO Charge Types and Equations" and "Format Specifications for Settlement Statement Files and Data Files", located on the Technical Interfaces page of our web site for details of these *charge types.*

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1.6.18 Intentionally Left Blank

Note:	The section 'Ontario Clean Energy Benefit' has been removed. The archived section can be found in Appendix E.9.

1.6.19 Renewable Integration - Forecasting

The *IESO* has established forecasting services as a procured service to accommodate *variable generation* from wind and solar resources. Forecasting services relating to *variable generation* implements one of the key principles of the *IESO*'s 'Renewable Integration Initiative' to integrate the influx of renewable generation into the *IESO-administered markets*.

The *settlement* of the forecasting charges follows the *IESO's* existing *physical market* invoicing process and timelines. Costs paid to the forecasting entities are treated as a procured service charge and recovered through a month-end non-hourly uplift charge to *consumer* loads and exports. *Charge type* 1600 "Forecasting Service Settlement Amount" will appear on the forecasting entity's *settlement statements* for the last trading day of the month. The corresponding setoff, *charge type* 1650 "Forecasting Service Balancing Amount", is included as an automatic charge on the *settlement statements* of all load and export customers for the last *trading day* of the month.

For more information on the *IESO's* Renewable Integration Initiative, refer to the following link: http://www.ieso.ca/-/media/files/ieso/document-library/engage/completed/renewable-integration_completed-engagement.pdf.

1.6.20 Adjustment for Self-Induced CMSC Earned by Certain Generating Facilities

If you are the *market participant* for a dispatchable *generating facility* or a dispatchable *electricity storage facility* that injects, the *IESO* may recover "self-induced" congestion management *settlement* credit (CMSC) payments from *generators* or *electricity storage participants* that inject under three specific scenarios in accordance with sections 3.5.6B, 3.5.6C and 3.5.6D of Chapter 9 of the *market rules* (but for clarity, *electricity storage participants* are only affected by the second scenario below*)*. Self-induced CMSC payments occur as the result of actions taken by the *generator* or *electricity storage participant* and/or conditions at, or involving, the *generation facility* or *electricity storage facility* and not by conditions on the *IESO-controlled grid*. As such, these CMSC payments are not consistent with the intent of CMSC payments. The three scenarios are:

- A *generation facility* that is eligible for a real-time generation cost guarantee (RT-GCG), disqualifies itself for the guarantee but could receive self-induced CMSC payments as a result;
- A *generation facility* or a dispatchable *electricity storage facility* that injects that either:
  i. is unable to follow *IESO dispatch instructions*, and/or
  ii. is *constrained on* or *constrained off* by the *IESO*, at the request of the *generator* or *electricity storage participant*, for safety, legal, regulatory, environmental or equipment damage reasons; could receive self-induced CMSC payments as a result.
- A *generation facility* (e.g. a steam turbine) fueled by another *generation facility* (e.g. a gas turbine) could receive self-induced CMSC payments as a result of the relationship between the facilities' *offer* prices and constraints applied by the *IESO* to recognize the operational dependencies of the two facilities. More specifically, this occurs when the steam unit *offer* is higher than the *offer* of the unit fuelling the steam unit.

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CMSC earned by the *generating facility* or a dispatchable *electricity storage facility* that injects in these specific scenarios is considered inappropriate as these payments are not consistent with the original intent of CMSC.

IESO staff will investigate these instances on an on-going basis and will notify you of the applicable CMSC recovery. You will have 5 *business days* to respond to the *IESO's* notification if you disagree. If you do not respond within 5 *business days*, the CMSC included in the *IESO's* notice shall be recovered.

The CMSC recovery is applied as a manual entry to *charge type* 124 "SEAL Congestion Management Settlement Credit Amount" on your *settlement statements* for the last *trading day* of the month. The adjustment is rebated back to *market participants* as a single manual entry to *charge type* 155 "Congestion Management Settlement Uplift" on the *settlement statements* for the last *trading day* of the month.

1.6.20.1 Calculation of CMSC Payment Recovery for Steam Unit Offers

When the *IESO* identifies a situation involving an inappropriate CMSC payment made to a *market participant* resulting from high steam unit *offers*, the *IESO* may recover that CMSC payment. If the *IESO* intends to recover the CMSC payments made to the steam unit, the *IESO* will prorate each output MW of the steam unit back to the *price-quantity pair* of the contributing combustion turbine unit to calculate the appropriate steam unit *offer*. The *IESO* will then recalculate the appropriate amount of CMSC based on the appropriate steam unit *offer,* and recover the inappropriate CMSC. The method by which the steam unit *offer* is calculated is identified below:

Steam Turbine (ST) is constrained to its operational minimum based on the number of combustion turbines (CTs) synchronized for Real-time Generation Cost Guarantee (RT-GCG)

- If one CT unit is offered/running at *minimum loading point* (MLP)
    - ST is operating at 1X1 MLP, the *offer* price should be no more than the CT MLP *offer* price
- If one CT unit is offered/running at above MLP
    - If the ST is operating above 1X1 MLP because the CT is operating above MLP, the *offer* price should be the CT MLP *offer* up to the ST MLP, then the next lamination of steam MWs should be offered at the next lamination of the CT *offer*.
- If two CT units are offered/running at MLP
    - The lowest cost combustion turbine unit (CT_1) MLP price would be used up to the ST 1X1 MLP, and the next lowest combustion turbine unit (CT_2) MLP price would be used up to the ST 2X1 MLP.
- If two CT units are offered/running at above MLP, causing steam injections above the 2X1 MLP:
    - The lowest cost combustion turbine ($CT_{1)}$ MLP *offer* would be used up to the ST 1X1 MLP, and the next lowest cost combustion turbine unit (CT_2) MLP price would be used up to the 2X1 MLP.
    - Above the 2X1 MLP, both CTs are considered to contribute equally to the steam injections, therefore above the 2X1 MLP; a weighted average price of the two contributing CTs would be used.

Example

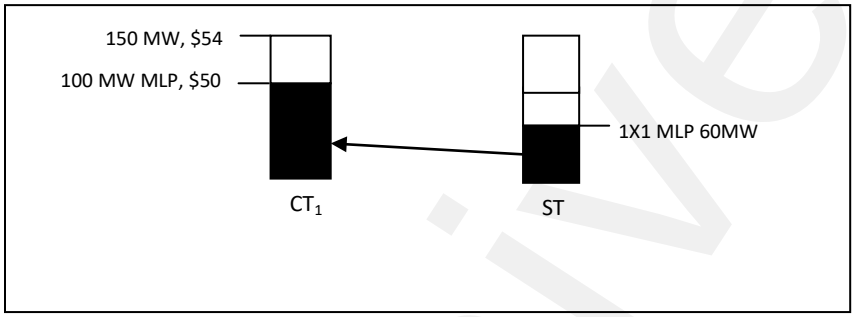
CT_1: gas unit, 100 MW MLP. *Offer* 100 MW @ $50, and up to 150 MW @ $54

CT_2: gas unit, 100 MW MLP. *Offer* 100 MW @ $52, and up to 150 MW @ $56

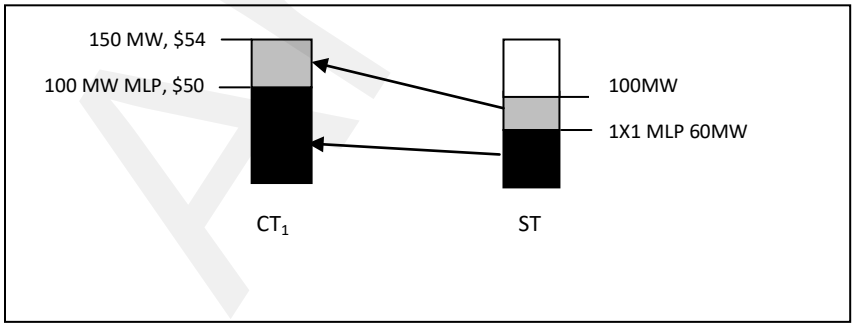
ST: steam unit, 1X1 MLP 60 MW, 2X1 MLP 100 MW, max 160 MW. *Offer* $200 for all injections.

The steam unit is considered to be fuelled by the lowest cost resource running.

- Figure 1 - If one combustion turbine (CT_1) is offered/running at MLP
  - ST is operating at 1X1 MLP (60 MW)
  - *offer* price should be no more than the CT_1 MLP *offer* price = $50

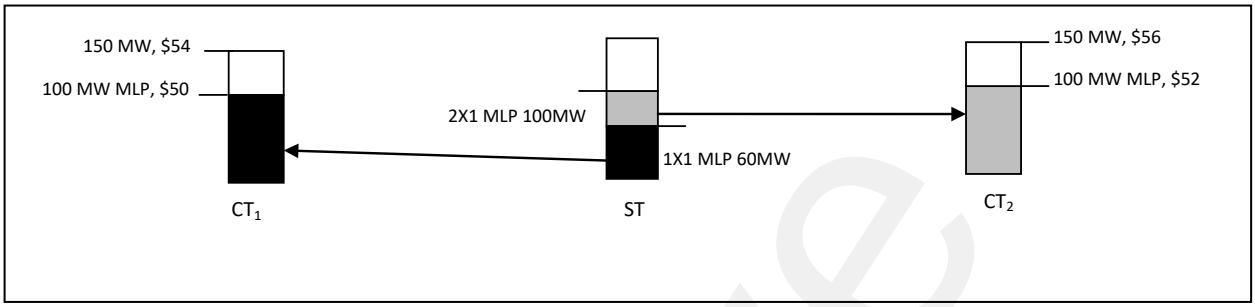


- Figure 2 - If one combustion turbine (CT_1) is offered/running at above MLP
  - ST is operating above 1X1 MLP (say 100 MW for example)
  - *Offer* price up to 1X1 MLP (60 MW) should be no more than the CT_1 MLP *offer* price of $50
  - *Offer* price for the 40 MW above 1X1 MLP should be the next lamination of CT_1 *offer* ($54)
  - Weighted average *offer* price for ST becomes [($50*60MW)+($54*40MW)]/(60MW+40MW)= $51.60

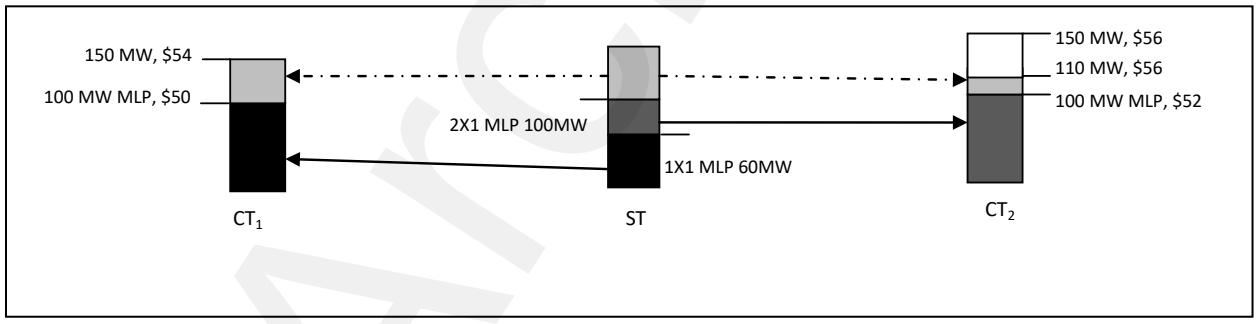


Archive

- Figure 3 - If two combustion turbines are offered/running at MLP.
  - Up to 1X1 MLP (60 MW) the ST *offer* price should be \$50 (CT_1)
  - Up to the 2X1 MLP (100 MW) the ST *offer* price should be \$52 (CT_2)
  - Weighted average *offer* price for steam unit becomes [(\$50*60MW)+(\$52*40MW)]/(60MW+40MW)= \$50.80



- Figure 4 - If two combustion turbines are offered/running at above MLP, causing steam injections above the 2X1 MLP (CT_1=150MW, CT_2=110 MW, steam injections of 140 MW)
  - Up to the 2X1 MLP of 100 MW, the *offer* price for the steam unit would be \$50.80 as above.
  - Above the 2X1 MLP, both combustion turbines are considered to contribute equally to the steam injections. The weighted average CT_1 and CT_2 price is [(\$54*50MW)+(\$56*10MW)]/(50MW+10MW) = \$54.33
  - The weighted average ST *offer* would be[(\$50.80*100MW)+(\$54.33*40MW)]/140 = \$51.81



1.6.21 Intentionally Left Blank

Note:	The section 'Limiting Constrained off CMSC Payments to Importers Injecting into Designated Chronically Congested Areas' has been removed as per market rules amendment MR-00423. For more details, refer to Appendix E.5, where the archived section can be found.

Archive

1.6.22 Limiting Payments to Exports during Negative Prices

Under certain system conditions an export can receive payments when withdrawing from the *IESO controlled grid*. This occurs when the *intertie* zonal price is negative. As of October 1, 2012, these payments to exports will be limited to a *settlement* floor price as determined by the *IESO* which has been stakeholdered with *market participants*. This is consistent with the *market rules* under Chapter 9, section 3.3.21.1 A, 3.5.6F and 3.8A.3.3.

Specifically, this limited payment to exports applies when the following conditions exist:

1) The *intertie* zonal price is less than the *settlement* floor price; and
2) The *intertie* is not import congested; and
3) The export is not part of a linked wheel.

As of February 1, 2013 the *settlement* floor price is -$2,000/MWh.

1.6.22.1 How Energy Payments Are Settled for Exports

The net *energy settlement* for an export transaction based on the conditions stated above will be the greater of:

- *Energy* market clearing price at the applicable *intertie zone*; and
- *Settlement* floor price as determined by the *IESO*.

This limiting payment to exports will be applied against *charge type* 1113 on the *settlement statements* on the last *trading day* of the month.

1.6.22.2 Limiting IOG Payments

Export quantities that are settled at the *settlement* floor price are excluded from the IOG offset process to be consistent with the treatment of negative price for exports. Refer to "Market Manual 9: Part 9.5 Settlement of the DACP" for details on the IOG Offset process.

1.6.23 Smart Metering Entity Charge

The Smart Metering Entity (SME) manages the meter data management /repository (MDM/R) to collect, manage, store and retrieve information related to the metering of electricity use in Ontario.

Effective May 1, 2013, the costs of developing and operating the MDM/R will be recovered by a Smart Metering Entity charge levied and collected from all licensed *distributors* (LDCs) identified in the *OEB*'s annual "Yearbook of Electricity Distributors". The Smart Metering Entity charge is the *OEB* approved rate per month for each LDC's Residential and General Service (<50 kW) customers. The latest Yearbook of Electricity Distributors available on January 1st is used to determine the Residential and General Service (<50 kW) customers for each LDC for that calendar year.

The Smart Metering Entity charge is applied monthly and includes the charges for the following month. C*harge type* 9980 "Smart Metering Charge" will appear on the *settlement statements* of each eligible LDC for the last *trading day* of the month.

1.6.24 Intentionally Left Blank

Note:	The section 'Capacity Based Demand Response Program' has been removed. The archived section can be found in Appendix E.10.

Archive

1.6.25 Biomass NUG and Energy from Waste (EFW) Contracts

The IESO has entered into individual procurement contracts for renewable generation supplied by Biomass Non-Utility Generation (NUG) and Energy from Waste (EFW) suppliers.

These contracts are not part of any pre-existing IESO programs. Each contract will be settled directly by the respective Local Distribution Company (LDC). The LDC will submit the difference between the contracted price and the wholesale market price to the *IESO* on a monthly basis. The information will be processed as a manual line item for the last *trading day* of the month.

Biomass NUG claims will be represented under *charge type* 1418 "Biomass Non-Utility Generation Contracts Settlement Amount" with the corresponding balancing *charge type* 1468 "Biomass Non-Utility Generation Contracts Balancing Amount".

Energy from Waste claims will be represented under *charge type* 1419 "Energy from Waste (EFW) Contracts Settlement Amount" with the corresponding balancing *charge type* 1469 "Energy from Waste (EFW) Contracts Balancing Amount".

The contract payments will be recovered through the global adjustment.

For more information on these contracts, refer to the following links:

Biomass Non-Utility Generation Contracts:
http://www.powerauthority.on.ca/about-us/directives-opa-minister-energy-and-infrastructure

Energy from Waste Generation:
http://www.powerauthority.on.ca/current-electricity-contracts/efw
http://www.powerauthority.on.ca/sites/default/files/page/8662_dec_19_08.pdf

1.6.26 Capacity Obligations

The *settlement* of *capacity obligations* and non-performance charges in this section apply only to *capacity market participants (CMPs)* with *capacity obligations*. For more information about the *capacity auction*, please refer to Market Rules Chapter 7 and Market Manual 12: "Capacity Auctions".

In this *market manual* references to the *demand response contributors* of residential *hourly demand response resources* in the "treatment group" and in the "control group" refer to the treatment group and control group of *demand response contributors* established in accordance with Market Manual 12: "Capacity Auctions".

Below is a table identifying the *settlement amounts* applicable to each type of resource that may have a *capacity obligation*:

		Resource Type					
		Capacity dispatchable load resources	*HDR resources*	*Capacity generation resource*	*Capacity storage resources*	*System-backed capacity import resources*	*Generator-backed capacity import resources*
Payments	*capacity auction* availability payment *settlement amount*	Yes	Yes	Yes	Yes	Yes	Yes

		Resource Type					
		Capacity dispatchable load resources	*HDR resources*	*Capacity generation resource*	*Capacity storage resources*	*System-backed capacity import resources*	*Generator-backed capacity import resources*
	capacity auction test activation payment *settlement amount* & *capacity auction* emergency operating state activation payment *settlement amount*	No	Yes	No	No	No	No
Non-Performance Charges	*capacity auction* availability charge *settlement amount*	Yes	Yes	Yes	Yes	Yes	Yes
	capacity auction administration charge *settlement amount*	No	Yes (only for virtual *HDR resources*)	No	No	No	Yes
	capacity auction dispatch charge *settlement amount*	No	Yes (only for C&I *HDR resources*)	No	No	No	No
	capacity auction capacity charge *settlement amount*	Yes	Yes	Yes	Yes	Yes	Yes
	capacity auction capacity import call failure *settlement amount*	No	No	No	No	No	Yes
	capacity auction	No	No	No	No	No	Yes

Archive

		Resource Type					
		Capacity dispatchable load resources	*HDR resources*	*Capacity generation resource*	*Capacity storage resources*	*System-backed capacity import resources*	*Generator-backed capacity import resources*
True-Ups	capacity deficiency *settlement amount*						
	capacity obligation in-period *cleared UCAP* adjustment charge *settlement amount*	No	Yes	No	No	No	No
	capacity obligation availability charge true-up *settlement amount*	Yes	Yes	Yes	Yes	Yes	Yes
	capacity obligation charge true-up *settlement amount*	Yes	Yes	Yes	Yes	Yes	Yes
Other	*capacity obligation* buy-out charge *settlement amount*	Yes	Yes	Yes	Yes	Yes	Yes

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1.6.26.1 Settlement Timelines

Capacity market participants with *capacity obligations* will be settled for *capacity auction settlement amounts* using the *physical markets settlement process*, and such *settlement amounts,* except those related to a buy-out process, will appear on the month-end *recalculated settlement statement* of the subsequent *energy market billing period,* resulting in a one-month lag. For clarity, those *settlement amounts* related to a buy-out process will appear on the next available *preliminary settlement statement* for the month end and will not be subject to a one-month lag.

1.6.26.2 Capacity Auction Availability Payment Settlement Amount

(*market rules:* ch. 9, s. 4.7J.1)

Capacity market participants with a *capacity obligation* will be paid a *capacity auction* availability payment *settlement amount* for every *energy market billing period* of the *commitment period* to which the *capacity obligation* relates, based on its *capacity obligation*.

The *IESO* uses *charge type* 1314 "Capacity Obligation – Availability Payment" to settle the *capacity auction* availability payment *settlement amount* to *CMPs*. *Charge type* 1314 will be settled on the first month-end *recalculated settlement statement* for the commitment month.

1.6.26.2A Capacity Auction Dispatch Test Payment and Capacity Auction Emergency Activation Payment Settlement Amounts

Hourly demand response resources will be compensated for each *settlement hour* of a *capacity auction dispatch test* or an activation that is in advance of or during an *emergency operating state.*

In order to determine the applicable measured *demand response capacity* (i.e. $HDRDC^{m}_{k,h}$), the *IESO* will determine the applicable Curtailed $MW^{m}_{k,h}$ in accordance with the following:

(a) For commercial and industrial *hourly demand response resources*, as follows:

$$\text{Curtailed MWh} = \text{Max}\ (0, (C\&I_HDR_BL^{m}_{k,h} - HDR_AC^{m}_{k,h})$$

Where:

- "$C\&I_HDR_BL^{m}_{k,h}$" is the calculated baseline *energy* consumption (in MWh) for *capacity market participant* 'k' at *delivery point* 'm' for the *hourly demand response resource* in *settlement hour* "h", calculated in accordance with section 1.6.26.3.1;
- "$HDR_AC^{m}_{k,h}$" is the total measured quantity of *energy* consumed (in MWh) for *capacity market participant* 'k' at *delivery point* 'm' for the *hourly demand response resource* in *settlement hour* "h", as determined in accordance with the submitted measurement data and AQEW, as the case may be.

(b) For residential *hourly demand response resources*, as follows:

$$\text{Curtailed MWh} = \text{Max}\ (0, TCTG^{m}_{k,h}\ X\ (ACGL^{m}_{k,h} - ATGL^{m}_{k,h}))$$

Where:

- "$TCTG^{m}_{k,h}$" is the absolute number of *demand response contributors* in the "Treatment group" for *capacity market participant* 'k' at *delivery point* 'm' for an *hourly demand response resource* for *settlement hour* 'h';
- "$ACGL^{m}_{k,h}$" is the average quantity of *energy* consumed (in MWh) by all of the *demand response contributors* in the "Control group" for *capacity market participant* 'k' at *delivery point* 'm' for an *hourly demand response resource* for *settlement hour* 'h', calculated in accordance with section 1.6.26.3.1; and
- "$ATGL^{m}_{k,h}$" is the average quantity of *energy* consumed (in MWh) by all of the *demand response contributors* in the "Treatment group" for *capacity market participant* 'k' at *delivery point* 'm' for an *hourly demand response resource* for *settlement hour* 'h', as determined in accordance with the submitted measurement data.

For the purpose of determining the appropriate *capacity auction dispatch test* payment *settlement amount,* HDRTAPR shall equal $250/MWh.

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For greater clarity, if measurement data for any *metering interval* is missing (i.e. measurement data was not submitted to the IESO), the *capacity auction dispatch test* payment *settlement amount* or emergency activation payment *settlement amount* for that *settlement hour* will be $0.

The IESO uses *charge type* 1320 "Capacity Obligation – Out of Market Activation Payment" to settle the *capacity auction dispatch test* payment *settlement amount* and the emergency activation payment *settlement amount*. *Charge type* 1320 will be settled on the first month-end *recalculated settlement statement* for the commitment month.

1.6.26.3 Non-Performance Charges

1.6.26.3.1 Hourly Demand Response (HDR) Baselines

Due to how *hourly demand response resources* participate and deliver into the *energy market*, baselines are required to determine certain *settlement amounts* applicable to *hourly demand response resources*. A baseline is an approximation of an *hourly demand response resource's* consumption profile that is used to estimate what the *hourly demand response resource* would have been consuming had an activation not taken place..

The *IESO* calculate baselines for each *hourly demand response resource* for the *settlement hours* in which there were activations.

For greater clarity, if the measurement data for any *metering interval* is missing (i.e. measurement data was not submitted), the consumption for such *metering interval* is deemed to be zero (0) when calculating the baseline.

Baseline Methodology for C&I Commercial & Industrial Hourly Demand Response Resources:

The baseline in a *settlement hour* for a commercial and industrial *hourly demand response resource* shall be calculated as follows:

$$C\&I_HDR_BL^{m}_{k,h} = StdBL^{m}_{k,h} \times IDAF^{m}_{k,h}$$

- Where: 'suitable *business days*' are any *business days* within the previous 35 *business day* period that meet the following criteria:
    1) For *business days* within the relevant *obligation period, business days* where the relevant commercial & industrial *hourly demand response resource*:
        a. placed at least one *demand response energy bid* for at least one *settlement hour* within the *availability window* for the *trading day*; and
        b. was not activated to provide *demand response capacity*; and
- For *business days* prior to the relevant *obligation period,* any *business day.*
- "$StdBL^{m}_{k,h}$" is the calculated *energy* consumption (in MWh) for *capacity market participant* 'k' at *delivery point* 'm' for an *hourly demand response resource* for *settlement hour* 'h', and calculated as the average of the measured *energy* consumption of the *hourly demand response resource* for the same hour-ending period of the 15 suitable *business days* which have the highest measurement data for the same hour-ending period in the last 20 suitable *business days* prior to the relevant activation.
- $IDAF^{m}_{k,h}$" is the In-Day Adjustment Factor for *capacity market participant* 'k' at *delivery point* 'm' for an *hourly demand response resource* for *settlement hour* 'h and calculated as:

Archive

$$IDAF^{m}_{k,h} = A \div B$$

Where:

- "A" is the hourly average energy consumption of the *hourly demand response resource* during the adjustment window hours on the trading day in which the *hourly demand response resource* was activated, as determined in accordance with the submitted measurement data.
- "B" is the hourly average energy consumption of the *hourly demand response resource* during the adjustment window hours in the 15 suitable *business days* which have the highest measurement data for the same adjustment window hours in the last 20 suitable *business days* prior to the relevant activation, as determined in accordance with the submitted measurement data.
- 'adjustment window hours' are those *settlement hours* which form the 3-hour period ending one hour prior to the relevant *activation window.* For example, if the *activation window* starts on HE 17, the adjustment window hours would be HE 13, 14, and 15.
- Notwithstanding the foregoing, the $IDAF^{m}_{k,h}$ shall not be less than 0.8 and shall not be greater than 1.2. For greater clarity, the $IDAF^{m}_{k,h}$ will be rounded either up or down if calculated as being less than 0.8 or greater than 1.2, respectively.
- Notwithstanding the foregoing, where the *IESO* is unable to identify 20 suitable *business days* within the relevant time period, the *IESO* shall utilize the following days in the calculation of the foregoing:
    - If the *IESO* identifies more than 15 but less than 20 suitable *business days*, the *IESO* shall use the 15 suitable *business days* which have the highest measurement data in those suitable *business days* identified; and
- If the *IESO* identifies 15 or fewer suitable *business days*, the *IESO* shall use all identified suitable *business days.*

Baseline Methodology for Residential Hourly Demand Response Resources:

Baseline Calculation:

The baseline in *settlement hour 'h'* of an activation event for a residential *hourly demand response resource* shall be calculated as follows:

$$ACGL^{m}_{k,h} = CGL^{m}_{k,h}/TCCG^{m}_{k,h} \times SDAF^{m}_{k,h}$$

Where:

- "$CGL^{m}_{k,h}$" is the total quantity of *energy* consumed (in MWh) by all of the *demand response contributors* in the "Control group" for *capacity market participant* 'k' at *delivery point* 'm' for an *hourly demand response resource* in *settlement hour* 'h', as determined in accordance with the submitted measurement data.
- "$TCCG^{m}_{k,h}$" is the absolute number of *demand response contributors* in the "Control group" for *capacity market participant* 'k' at *delivery point* 'm' for an *hourly demand response resource* for s*ettlement hour* 'h';
- "$SDAF^{m}_{k,h}$" is the Same-Day Adjustment Factor for *capacity market participant* 'k' at *delivery point* 'm' for an *hourly demand response resource* for *settlement hour* 'h and calculated as:

Archive

$$SDAF^{m}_{k,h} = C \div D$$

Where:

- "C" is the hourly average energy consumption of all of the *demand response contributors* in the "Treatment group" during the adjustment window hours of the relevant *trading day* divided by the absolute number of *demand response contributors* in the "Treatment Group".
- "D" is the hourly average energy consumption of all of the *demand response contributors* in the "Control Group" during the adjustment window hours of the relevant *trading day* divided by the absolute number of *demand response contributors* in the "Control Group".
- "adjustment window hours" are those *settlement hours which form* the 3 hour period ending 1 hour prior to the relevant activation window. For example, if the activation starts on HE 17, the adjustment window hours would be HE 13, 14, and 15.

1.6.26.3.2 Capacity Auction Availability Charge Settlement Amount

(*market rules*: Ch. 9, s. 4.7J.2.1)

The *capacity auction* availability charge *settlement amount* applies when *capacity market participants* with *capacity obligations* fail to submit and maintain their *demand response energy bids* or *energy offers,* as applicable*,* for the day-ahead commitment process through to pre-dispatch and until *real-time market* for *auction capacity* at least equal to their *capacity obligation*. The charge is calculated for each *settlement hour* within the *availability* window of the *obligation period* for each *capacity auction resource*.

For the settlement of the availability charges, a non-performance factor (CNPF) multiplier is used based on the applicable month as per Section 6.1 of Market Manual 12: "Capacity Auctions".

The *IESO* uses *charge type* 1315 "Capacity Obligation – Availability Charge" to settle the *capacity auction* availability charges. *Charge type* 1315 will be settled on the first *recalculated settlement statement* for the *trading day*.

Assessment for Capacity Generation Resources

The *IESO* will apply an availability charge to any *settlement hour* within the *availability window* where *capacity market participants* participating with a *capacity generation resource* fail to submit an *energy offer* for their *capacity generation resource* for an amount greater than or equal to their *capacity obligation* quantity in the following periods:

1. in the day-ahead commitment process; and
2. in *pre-dispatch* for each *pre-dispatch* that occurs prior to the earliest of the commencement of the following:
    1. the 2-hour mandatory window applicable to the relevant hour of the *availability window*;
    2. a period of time equal to the *capacity generation resource's* registered *elapsed time to dispatch* that is prior to the relevant hour of the *availability window;* and
    3. a period of time equal to the *capacity generation resource's minimum generation block down time* that is prior to the relevant hour of the *availability window.*

1.6.26.3.3 Capacity Auction Administration Charge Settlement Amount

The *capacity auction* administration charge *settlement amount* applies when *capacity market participants* with *hourly demand response resources* that are not revenue-metered by the *IESO* or *capacity market participants* with *generator-backed capacity import resources* fail to provide timely, accurate and complete data, including measurement data, to the *IESO* in accordance with the timelines and requirements of section 5.3.3 and 5.3.4 of *market manual* 12.

The administration charge will also be applicable to a *capacity market participants* with a virtual *hourly demand response resource* if the submitted measurement data is determined to be inaccurate during an audit conducted by the *IESO*.

The *IESO* uses *charge type* 1316 "Capacity Obligation – Administration Charge" to settle the *capacity auction* administration charge *settlement amount. Charge type* 1316 will be settled on the first month-end *recalculated settlement statement* for the commitment month.

1.6.26.3.4 Capacity Auction Dispatch Charge Settlement Amount

(*market rules*: Ch. 9, s. 4.7J.2.2 and 4.7J.4)

- The *capacity auction* dispatch charge *settlement amount* is applicable only to commercial & industrial *hourly demand response resources* that are determined to have failed to follow their *dispatch instructions* during an activation, including *capacity auction dispatch tests* and *capacity auction capacity tests,* for any *dispatch interval* within the *settlement hour,* as determined in accordance with section 4.7J.2.2.1 of Chapter 9. .

For greater clarity, if measurement data for the interval required for "Actual Consumption" is missing (i.e. measurement data was not submitted), $C\&I_HDR_BL^{m,t}_{k,h}$ - $HDR_AC^{m,t}_{k,h}$ in the formula outlined in section 4.7J.2.2.1 of Chapter 9 is 0.

The *IESO* uses *charge type* 1317 "Capacity Obligation – Dispatch Charge" to settle the *capacity auction* dispatch charge *settlement amount. Charge type* 1317 will be settled on the first *recalculated settlement statement* for the *trading day*.

1.6.26.3.5 Capacity Auction Capacity Charge Settlement Amount

(*market rules*: Ch. 9, s. 4.7J.2.4 and 4.7J.4)

The capacity charge is applicable to all participating *capacity auction resources* when they fail the *capacity auction capacity test*, as determined in accordance with Section 5.3.3 of Market Manual 12: "Capacity Auctions". The capacity charge for a failed *capacity auction capacity test* is equal to one month's availability payment.

The *IESO* uses *charge type* 1318 "Capacity Obligation – Capacity Charge" to settle the capacity charges. *Charge type* 1318 will be settled on the first month-end *recalculated settlement statement* for the commitment month.

Assessment for HDR Resources

The charge applies when the resource fails the *capacity auction capacity test* as determined in accordance with Section 5.3.4 of Market Manual 12: Capacity Auctions.

The *IESO* will assess Commercial & Industrial and residential *hourly demand response resources* as described below.

Capacity Charge Assessment for C&I *HDR Resources*:

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A C&I *HDR resource* will be determined to have failed to provide *auction capacity* if any *settlement hour* of the following condition is true for any *settlement hour* of the *capacity auction capacity test*:

$$\Sigma^{T}(C\&I_HDR_BL^{m,t}_{k,h} - HDR_AC^{m,t}_{k,h})/12 < 90\% \times CICAP^{m}_{k,h}$$

Where:

- "C&I $HDR_BL^{m,t}_{k,h}$" is the amount calculated pursuant to section 1.6.26.3.1.
- "$HDR_AC^{m,t}_{k,h}$" is the total measured quantity of *energy* consumed (in MW) for *capacity market participant* 'k' at *delivery point* 'm' for the *hourly demand response resource* in *metering interval* 't' of *settlement hour* "h", as determined in accordance with the submitted measurement data and AQEW, as the case may be
- 'T' is the set of all *metering intervals* within the relevant *settlement hour.*

For greater clarity, if measurement data for the interval required for "Actual Consumption" is missing (i.e. measurement data was not submitted), (C&I *HDR* $_BL^{m,t}_{k,h} - HDR_AC^{m,t}_{k,h}$), in the above formula is 0.

Capacity Charge Assessment for Residential HDRs:

A residential *hourly demand response resource* will be determined to have failed to provide *auction capacity* if the following condition is true for the *capacity auction capacity test*:

$$\Sigma^{H}[(ACGL^{m}_{k,h} - ATGL^{m}_{k,h}) \times TCTG^{m}_{k,h}]/4 < 90\% \times CICAP^{m}_{k,h}$$

Where:

- "$ACGL^{m}_{k,h}$" is the amount calculated pursuant to section 1.6.26.3.1.
- "$ATGL^{m}_{k,h}$".

For greater clarity, if measurement data for the *settlement hour* required are missing (i.e. measurement data was not submitted), or monthly residential contributor information was not submitted, ($ACGL^{m}_{k,h} - ATGL^{m}_{k,h}$) in the above formula is zero (0).

1.6.26.3.6 Capacity Auction Capacity Import Call Failure Settlement Amount

(*market rules*: Ch. 9, s. 4.7J.2.7)

The *capacity auction capacity import call* failure charge *settlement amount* applies to *generator-backed capacity import resources* that fail to deliver the called upon *auction capacity* in response to a *capacity import call* in accordance with the process outlined in Section 6.8.1 of Market Manual 4.3: "Real-time Scheduling of the Physical Markets".

The *IESO* uses *charge type* 1321 "Capacity Obligation – *Capacity Import Call* Failure Charge" to settle the *capacity auction* capacity import failure *settlement amount*. *Charge type* 1321 will be settled on the first month-end *recalculated settlement statement* for the commitment month.

1.6.26.3.7 Capacity Auction Capacity Deficiency Settlement Amount

(*market rules*: Ch. 9, s. 4.7J.2.8)

The *capacity auction* capacity deficiency *settlement amount* will apply to *generator-backed capacity import resources* deemed to have *over committed capacity* in accordance with the process outlined in Section 3.3 of Market Manual 12: "Capacity Auctions".

The *IESO* uses *charge type* 1322 "Capacity Obligation – Capacity Deficiency Charge" to settle the *capacity auction* capacity deficiency *settlement amount.* *Charge type* 1322 will be settled on the first month-end *recalculated settlement statement* for the commitment month.

1.6.26.3.8 In-Period Cleared UCAP Adjustment Charge

(*market rules:* Ch. 9, s. 4.7J.2.9)

The in-period *cleared UCAP* adjustment charge *settlement amount* claws back availability payments for *auction capacity* which exceeds the *auction capacity* demonstrated in the *capacity auction capacity test.* Where the *capacity market participant* agrees with the findings of the *capacity auction capacity test*, and does not submit a *notice of disagreement*, the in-period *cleared UCAP* adjustment charge *settlement amount* will apply starting from the first *business day* of the *obligation period* and ending on the day on which section 19.4.18 of Chapter 7 applies to reduce the *capacity market participant's capacity obligation.* Where the *capacity market participant* disagrees with the findings of the *capacity auction capacity test*, by submitting a *notice of disagreement,* the in-period *cleared UCAP* adjustment charge *settlement amount* will apply for every *energy market billing period* of the *obligation period* and any adjustment resulting from the *notice of disagreement* process will be made as necessary.

Any in-period *cleared UCAP* adjustment will not be reassessed as a result of a measurement data audit conducted pursuant to Market Manual 12: Capacity Auctions.

The *IESO* uses charge type 1323 "Capacity Obligations – in-period *cleared UCAP* adjustment charge" to settle this charge. *Charge type* 1323 will be settled on the first month-end *recalculated settlement statement* for the commitment month.

1.6.26.4 Non-Performance Charge Exceptions

In limited circumstances, a *capacity market participant* may request a reduction or reversal of a previously levied *capacity auction* availability charge and/or a *capacity auction* dispatch charge *settlement amount*.

In order to request such an adjustment, a *capacity market participant* must submit such request using the *notice of disagreement* process in accordance with the timelines and requirements thereof and must include supporting documentation and evidence to substantiate the allowable exception.

The allowable exceptions are subject to *IESO* approval and are as follows:

a) Inability of an otherwise available resource to submit *demand response energy bids or energy offers,* as applicable*,* for some or all of the *capacity obligation* due to the *outage* of a third party *market participant* (e.g. a transmission *outage*):
    i. For such an allowable exception to apply, the required supporting documentation must include proof, originating from that third party market participant, to the IESO that the failure to provide auction capacity was due to the outage of that third party market participant.
b) Inability for a resource associated with a *capacity obligation* to provide *auction capacity* due to a *force majeure event*, and:
    i. For such an allowable exception to apply, the *capacity market participant* must first adhere to the force majeure requirements (Chapter 1, section 13.3) of the *market rules* prior to submitting the *notice of disagreement* process requesting the application of the allowable exception. The *IESO* shall not approve a request unless the *IESO* is satisfied that the *capacity market participant* has met the notification requirements for a *force majeure event*, and that force majeure conditions have been met.

Table 1–4: Scenarios and Adjustments for Exceptions

Scenarios	Adjustments	
	Availability Charges	**Dispatch Charges**
Third Party *Outage*,	The affected resource is deemed to have submitted *demand response energy bid/energy offer* and the charge is re-assessed using the impacted quantity assessed by the *IESO*.	Not applicable for the portion impacted by the *outage* since no *bids* were submitted.
Force Majeure	The charge is re-calculated using a non-performance factor of 1.0.	The charge will be reversed (applicable to HDRs only).

1.6.26.5 Buy-Out Charges

Upon *IESO*'s acceptance of a *capacity market participant* or *capacity auction participant's* buy-out request (refer to the buy-out process as detailed in Section 7 of Market Manual 12: "Capacity Auctions"), the *IESO* will calculate a *capacity obligation* buy-out *settlement amount*. The buy-out charge will appear on the *preliminary settlement statement* for the last day of the *energy market billing period* in which the *IESO* accepted the buy-out request.

The *IESO* uses *charge type* 1319 "Capacity Obligation – Buy-Out Charge" to settle the *capacity auction* buy-out *settlement amount*. If the buy-out capacity is not the *capacity market participant* or *capacity auction participant's* entire *capacity obligation* amount, then the *IESO* will settle the remainder of the *obligation period* with the revised *capacity obligation* amount (i.e. original *capacity obligation* minus the buy-out capacity). *Charge type* 1319 will be settled on the next available month-end *preliminary settlement statement*.

1.6.26.6 Availability Charges True-Up Payment

(*market rules:* Ch. 9, s. 4.7J.6)

At the end of each *obligation period* the *IESO* will determine *capacity obligation* availability charge true-up *settlement amount* for all *capacity market participants* who meet the conditions set out in the *market rules.*

To determine the amount of excess capacity offered, the *capacity obligation* availability charge true-up *settlement amount* considers the difference between the *capacity auction resource's capacity obligation* and the minimum of:

- *capacity auction resource's energy bids* or *energy offers* as applicable (i.e. $DREBQ^{m}_{k,h}$ and $CAEO^{m}_{h,k}$)
- *Capacity auction resource's cleared ICAP* (i.e. $CICAP^{m}_{k}$)
- 115% of a *capacity auction resource's capacity obligation* (i.e. 1.15* CCO^{m}_{k})
- *Capacity auction resource's demand response contributors* total registered capability (applicable only to virtual *HDR resources*) (i.e. $CARC_{k}^{m}$)

The *capacity auction resource's capacity obligation* used in the determination of the *capacity obligation* availability charge true-up *settlement amount*, in both the calculation itself and the determination of RAC^{m}_{k}, is the *capacity obligation* as of the relevant *settlement hour.*

The *capacity obligation* availability charge true-up *settlement amount* is effectively capped at the total dollar value of the charges the *capacity auction resource* incurred pursuant to section 4.7J.2.1 or 4.7J.2.1A and 4.7J.2.9, as applicable, during the applicable *obligation period.*

The IESO uses charge type 1324 "Capacity Obligation – Availability Charges True-Up Payment" to settle the true-up. *Charge type* 1324 will be settled on the *recalculated settlement statement* of the last commitment month of the *obligation period*.

1.6.26.7 Capacity Obligation Capacity Auction Charges True-Up Payment

(*market rules:* Ch. 9, s. 4.7J.7)

At the end of each *obligation period* the *IESO* will determine *capacity obligation capacity auction* charge true-up *settlement amount* for all *capacity market participants* with *capacity obligations* during such *obligation period* in accordance with Section 4.7J.7 of Chapter 9 of the *market rules.*

The *IESO* uses charge type 1325 "Capacity Obligations – Capacity Auction Charges True-up Payment" to settle this charge. *Charge type* 1325 will be settled on the *recalculated settlement statement* of the last commitment month of the *obligation period*.

1.6.26.8 Capacity Auction Uplift Settlement Amount

At the end of each *energy market billing period* the *IESO* will recover the cost, if any, of all *capacity auction settlement amounts* by allocating such costs to *consumers* utilizing the same allocation methodology used for the Global Adjustment.

Refer to section 1.6.7.8 for details on the determination or allocation for Class A and Class B loads for the Global Adjustment.

Please refer to the Charge Types and Equations document to find the definitions of the following variables: $EGEI_k$, EEQ, Class B Load, $GA_AQEW_{g,k,h,M}^{m,t}$, $PGS_{h,M}$.

The *IESO* uses charge type 1350 "Capacity Based Recovery Amount for Class A Loads" to settle the *capacity auction* uplift *settlement amount* for *market participants* that are classified as a 'Class A Market Participants'.

The *IESO* uses charge type 1351 "Capacity Based Recovery Amount for Class B Loads" to settle the *capacity auction* uplift *settlement amount* for *market participants* that are classified as 'Class B Market Participants'.

1.6.27 Transmission Rights Clearing Account Disbursement

The *IESO* will review the Transmission Rights Clearing account (TRCA) balance on a semi-annual basis and disburse the surplus funds when the balance exceeds the Reserve Threshold by at least $5M, or as directed by the *IESO Board*.

As per section 4.7 of Chapter 9, the surplus funds will be split into two classes based on the proportion of total provincial transmission service charges (*Charge Type* 650, 651 and 652) and total export transmission service charges (*Charge Type* 653) collected from the market during the six (6) month period immediately preceding the month-end on which it will be disbursed ("balance period"), or as directed by the *IESO Board*. For example, the surplus funds at the end of April 30, 2021 will be split among the loads and exporters based on the total dollar amount of provincial transmission charges and export transmission charges collected from the market from November 1, 2020 to April 30, 2021. Similarly, the surplus funds at the end of October 31, 2021 will be split based on the total

dollar amount of provincial transmission charges and export transmission charges collected from the market from May 1, 2021 – October 31, 2021.

Each class of funds will then be settled as a single payout based on the total allocated quantity of *energy* withdrawn over a six (6) month prior period ("look-back period"), or as directed by the *IESO Board*. The surplus funds allocated to loads are distributed based on the *energy* withdrawn at all *RWM*s excluding any *intertie metering points.* The surplus funds allocated to exporters are distributed based on the *energy* withdrawn at all *intertie metering points*. The disbursement will be distributed to *market participants* as a non-hourly *settlement amount* on a month-end *settlement statement* as *charge type* 102 "TR Clearing Account Credit" as per Chapter 9, section 4.7 of the *market rules*.

For example, disbursement of the surplus funds available at the end of April 30, 2021 will be applied to the *market participants*' May 31, 2021 *preliminary settlement statement*, based on their total allocated quantity of *energy* withdrawn over the six (6) month look-back period of December 1, 2020 to May 31, 2021. Similarly, disbursement of the surplus funds at the end of October 31, 2021 will be applied to *market participants'* November 30, 2021 *preliminary* and *final settlement statements* based on their total allocated quantity of *energy* withdrawn over the six (6) month look-back period of June 1, 2021 to November 30, 2021.

1.6.28 Limiting Constrained-off CMSC to Interties

If you are a *market participant* that has offered to inject or withdraw *energy* over an *intertie*, you may have been constrained off by the *IESO* and may be eligible for constrained off congestion management *settlement* credit (CMSC) payments from the Ontario marketplace. Under section 3.5.10, Chapter 9 of the *market rules*, the *IESO* will withhold or recover these *constrained*-off CMSC payments if the *intertie* transaction was constrained-off in the final pre-dispatch run prior to the *dispatch hour*. However, a *market participant* will continue to receive constrained-off CMSC for an *intertie transaction* if the *intertie transaction* was constrained-off manually by the *IESO* for the purpose of Ontario *reliability* after the final pre-dispatch run.

1.6.28.1 Interaction between Negative CMSC and IOG

Negative CMSC currently offsets *intertie offer* guarantee (IOG) payments for eligible import transactions when constrained-off. Therefore, if you are a *market participant* that has offered to inject over an *intertie* and have received an IOG payment as defined in Chapter 9, section 3.8A of the *market rules*, you will continue to receive any applicable negative constrained-off CMSC charges.

If the import transaction was part of an implied linked wheel and you did not receive an IOG payment, you will continue to receive any applicable negative constrained-off CMSC charges as per section 3.5.10, Chapter 9 of the *market rules*.

1.6.29 Ontario Electricity Support Program

The Ontario Electricity Support Program (OESP) was established by the Ministry of Energy to provide assistance to eligible low-income electricity *consumers* following the conclusion of the Ontario Clean Energy Benefit (OCEB) on December 31, 2015. Based on income level and household size, the qualified low-income electricity *consumers* will receive a predetermined credit on their electricity bills.

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As described in the Ontario Regulation 314/15, the *IESO* will distribute funds to *distributors* and unit sub-meter providers for the OESP credits they have applied to eligible *consumers*' bills and compensate service providers[14] for the administrative costs for OESP.

The disbursed funds will be settled as a manual line item on the *settlement statements* for the last trading day of the month under *charge type* 1420 "Ontario Electricity Support Program Settlement amount".

Distributors and unit sub-meter providers that are *market participants* must submit OESP claims to us via the on-line form "Ontario Electricity Support Program – LDC & USMP". Licensed *distributors* will submit OESP claims both for themselves and also on behalf of the embedded *distributors*. In order to obtain reimbursement from the *IESO*, service providers must be registered as program participants and submit OESP claims to the *IESO* using the settlement form "Ontario Electricity Support Program – Service Providers" which is accessible via Online IESO. All OESP claims for the current *settlement* month must be received by the *IESO*, no later than the fourth *business day* after the last trading day of the month.

If any changes are required to the amounts submitted during the preliminary submission period, final adjustments can be submitted during the 11th to 14th *business day* after the last *trading day* of the month. The adjustments will be reflected on the *final settlement statement* for the last *trading day* of the month. Furthermore, post final adjustments can be submitted through Online IESO for any previous settlement period. Any amount submitted as a post final adjustment will be settled on the *preliminary settlement statement* for the last *trading day* of the current settlement month.

1.6.30 Adjustment Account Surplus Disbursement

The *IESO* will review, at least annually, the allocation of any credit balance in the *IESO adjustment account* as directed to by the IESO Board. The IESO Board may direct that some or all of the credit balance (surplus) be distributed to *market participants* as a rebate. The disbursement will be settled as a single payout based on the total allocated quantity of *energy* withdrawn over a prior period as determined by the IESO Board. The disbursement will be distributed to *market participants* as a non-hourly *settlement amount* on a month-end *settlement statement* under *charge type* 9920, "Adjustment Account Credit" as per Chapter 9, section 6.18.6.3 of the *market rules*.

For example, if the disbursement of a credit balance (surplus) is to be applied to the February 29, 2016 *preliminary settlement statement* for the preceding six (6) month prior period, the credit balance will be distributed to *market participants* based on their total allocated quantity of *energy* withdrawn over the prior period of September 1, 2015 to February 29, 2016.

1.6.31 Limiting Constrained On CMSC Payments to Generators and Electricity Storage Participants Ramping Down

In order to signal its desire to come offline, a *generator* must submit an *offer* price that exceeds the shadow price at its node, but which may not represent the *generator's* cost. The *generator* is dispatched down incrementally, according to the *generator's offered* ramp-down rates, until the *generator* receives a *dispatch* schedule of zero. During the ramp-down intervals, the *generator* is constrained-on and may receive CMSC for the implied shortfalls in operating profit. There is potential for a *generator* or *electricity storage participant* that injects to earn significant self-induced CMSC during ramp-down. As such, as of December 8, 2016, non-quick start *generators* and non-quick start *electricity storage participants* will no longer be eligible for CMSC during intervals where

[14] The service providers are the entities as defined by OESP regulation, O. Reg. 314/15.

the *facility* is constrained-on while ramping down to come offline, unless activated for *operating reserve* or constrained under a GCG or PCG during the ramp-down interval.

The IESO will withhold or recover all CMSC during the ramp-down period; however, the *generator* or *electricity storage participant* will receive compensation in the form of a ramp-down *settlement amount* (RDSA) representing the cost of ramping down during the ramp-down period. This is consistent with the *market rules* under Chapter 9, section 3.5.1G and 3.5A.1.

The RDSA is calculated as the lesser of the CMSC withheld or recovered and the calculated ramp-down compensation (RDC), as per Chapter 9, section 3.5A.1 of the *market rules*.

A ramp down period is defined as a set of consecutive intervals that meet one of the following criteria and ends when there is no *dispatch* or a zero MWh *dispatch instructions*

- Ramp-down rate limited (RDRL) [15];
- *Dispatch instructions* is below the registered *minimum loading point*; or
- Revised *dispatch instructions* is sent due to *dispatch* deviation,

The start of the ramp-down period is the first interval in the set of consecutive intervals.

The ramp-down factor (RDF) is a factor used in the calculation of RDC to adjust the *generator's* or *electricity storage participant's offer* for the *settlement hour* immediately preceding the hour in which the ramp-down began; this adjusted *offer* is then used to calculate RDC for all ramp-down intervals. The RDF is intended to provide the *generator* with reasonable compensation to drive efficient operation while mitigating self-induced CMSC. The RDF is defined as follows:

- 1.0, when *dispatch* is equal to or greater than the registered MLP; and
- 1.3, when *dispatch* is below registered MLP.

The calculation of RDSA will be limited to the ramp-down intervals for the *trading day* in which the *generator* went offline. In the event that a ramp-down period crosses over from the previous *trading day*, any CMSC earned in the previous *trading day* will not be adjusted. If a *generator* or *electricity storage participant* comes online but does not reach MLP before going offline any CMSC earned during ramp-down will not be adjusted.

1.6.32 Ontario Rebate for Electricity Consumers Act, 2016

The *Ontario Rebate for Electricity Consumers Act, 2016* ("OREC") has been established by the Ministry of Energy, Northern Development and Mines to provide financial assistance for certain Ontario electricity *consumers* in respect of electricity costs. As described in the Act and Ontario Regulations 363/16 and 364/16, consumers with eligible accounts receive a reduction in the amount payable before tax under their electricity accounts for each billing period. The Act and the regulations have been in force as of January 1, 2017.

Ontario Regulation 363/16 requires the *IESO* to reimburse licensed distributors that are *market participants* for the financial assistance they have provided to consumers that have eligible accounts with: the distributor; any wholly-embedded distributors of which the licensed distributor is the host distributor; and any licensed retailers that use retailer-consolidated billing for financial assistance and that conduct business in the licensed distributor's service area or the service area of a wholly-embedded distributor for whom the licensed distributor is the host distributor. The regulations also

[15] Ramp-down rate limited (RDRL) means that the calculated *dispatch instructions* is 'limited' by the generator's offered ramp rate.

requires the *IESO* to reimburse unit sub-meter providers[16] for the financial assistance they have provided to consumers that are entitled to receive financial assistance. A consumer who is a *market participant* and has an eligible account is entitled to have a credit equal to the applicable financial assistance appear on their invoice for each billing period.

Licensed distributors and unit sub-meter providers that are *market participants* must submit their claims for reimbursement to *IESO* monthly no later than the fourth *business day* after the last *trading day* of the month. The *settlement amount* for licensed distributors and unit sub-meter providers will be included on the *preliminary settlement statement* for the last *trading day* of the month.

If any changes are required to the amounts submitted during the preliminary submission period, final adjustments can be submitted during the 11th to 14th *business days* after the last *trading day* of the month. The adjustments will be reflected on the *final settlement statement* for the last *trading day* of the month. Furthermore, post-final *settlement statement* adjustments can be submitted through Online IESO for any previous settlement period. Any amount submitted as a post-final *settlement statement* adjustment will be settled on the *preliminary settlement statement* for the last *trading day* of the current settlement month.

1.6.32.1 Settlement of Ontario Rebate for Electricity Consumers (OREC) Claims

The 8% reduction of the base invoice amount under the OREC for eligible consumers was in effect for the billing periods from January 1, 2017 to October 31, 2019.

Licensed distributors and unit sub-meter providers that are *market participants* must submit their OREC claims to *IESO* via the settlement form "Ontario Rebate for Electricity Consumers (OREC) – LDC & USMP" as post-final adjustments.

The OREC *settlement amount* for licensed *distributors* and unit sub-*meter* providers will be included on the *settlement statements* for the last *trading day* of the current settlement month through *charge type* 9982 "Ontario Rebate for Electricity Consumers (8% Provincial Rebate) Settlement Amount".

The corresponding set-off is *charge type* 1467 "Ontario Rebate for Electricity Consumers (8% Provincial Rebate) Balancing Amount" on Ministry of Energy, Northern Development and Mines *preliminary* and *final settlement statements*.

1.6.32.2 Settlement of Ontario Rebate for Electricity (OER) Claims

The 33.2% reduction of the base invoice amount under the OER for eligible consumers is in effect for the billing periods beginning November 1, 2020.

Licensed distributors and unit sub-meter providers that are *market participants* must submit their OER claims to *IESO* via the settlement form "Ontario Electricity Rebate (OER) – LDC & USMP".

The OER *settlement amount* for licensed *distributors* and unit sub-*meter* providers will be included on the *settlement statements* for the last *trading day* of the month under *charge type* 9983 "Ontario Electricity Rebate Settlement Amount".

The corresponding set-off is *charge type* 1457 "Ontario Electricity Rebate Balancing Amount" on Ministry of Energy, Northern Development and Mines *settlement statements*.

[16] "Unit sub-meter provider" is defined in the Ontario Rebate for Electricity Consumers Act, 2016.

1.6.32.3 Settlement of OREC-OESP Variance

Unit sub-*meter* providers that submitted both OREC and OESP claims for the billing periods from January 1, 2017 to October 31, 2019 on behalf of eligible consumers must remit OREC-OESP variance to *IESO* via the settlement form "OREC-OESP Variance – USMP" as post-final adjustments.

The OREC-OESP variance *settlement amount* for unit sub-*meter* providers will be included on the *settlement statements* for the last *trading day* of the current settlement month through *charge type* 9982 "Ontario Rebate for Electricity Consumers (8% Provincial Rebate) Settlement Amount".

The corresponding set-off is *charge type* 1467 "Ontario Rebate for Electricity Consumers (8% Provincial Rebate) Balancing Amount" on Ministry of Energy, Northern Development and Mines *settlement statements*.

1.6.32.4 Settlement of OER-OESP Variance

Unit sub-*meter* providers that submitted both OER and OESP claims for the billing periods effective November 1, 2019 on behalf of eligible consumers must remit OER-OESP variance to *IESO* via the settlement form "OER-OESP Variance – USMP" as post-final adjustments.

The OER-OESP variance *settlement amount* for unit sub-*meter* providers will be included on the *settlement statements* for the last *trading day* of the current settlement month through *charge type* 9983 "Ontario Electricity Rebate Settlement Amount".

The corresponding set-off is *charge type* 1457 "Ontario Electricity Rebate Balancing Amount" on Ministry of Energy, Northern Development and Mines *settlement statements*.

1.6.33 Fair Hydro Act, 2017

The *Fair Hydro Act, 2017* (Bill 132) makes amendments to the *Electricity Act, 1998*, and the *Ontario Energy Board Act, 1998,* implementing a variety of initiatives broadly targeting residential customers along with some small businesses and farms. Additional programs being implemented under the *Act* specifically relate to residential customers in rural or remote areas and First Nations reserves.

1.6.33.1 Intentionally Left Blank

Note: The section 'Global Adjustment Modifier' has been removed as per amendment to regulation. For more details, refer to Appendix E.13, where the archived section can be found.

1.6.33.2 First Nations On-reserve Delivery Credit

As part of the *Fair Hydro Act, 2017*, the First Nations On-reserve Delivery Credit (FNDC) provides a credit to a customer of a licensed distributor that occupies residential premises located on or within a reserve and has a residential-rate account with that distributor. The amount of the delivery credit is prescribed in Ontario Regulation O. Reg 197/17.

Licensed *distributors* must submit their claims for reimbursement of the FNDC credits paid to their eligible customers. These claims must be submitted monthly to the IESO no later than the fourth *business day* after the last *trading day* of the month. The *settlement amount* for licensed *distributors* will be included on the *settlement statements* for the last *trading day* of the month under *charge type* 705 "Ontario Fair Hydro Plan First Nations On-reserve Delivery Amount". The corresponding set-off is *charge type* 755 "MOE - Ontario Fair Hydro Plan First Nations On-reserve Delivery Balancing Amount".

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1.6.33.3 Distribution Rate Protection

As part of the *Fair Hydro Act, 2017*, the Distribution Rate Protection (DRP) program sets maximum monthly base distribution charges for eligible residential customers of certain utilities. The eligibility requirements can be found in Ontario Regulation O. Reg 198/17. The maximum monthly base distribution rate is set at least once a year by the Ontario Energy Board (OEB). As the DRP program caps the base distribution charges, distributors must calculate the actual total base distribution charge and compare this to the maximum charge approved by the OEB and charge no more than the maximum amount.

Licensed *distributors* must submit their claims for reimbursement of the DRP credits paid to their eligible customers. This claim must be submitted monthly to the IESO no later than the fourth *business day* after the last *trading day* of the month. The *settlement amount* for licensed *distributors* will be included on the *settlement statements* for the last *trading day* of the month under *charge type* 706 "Ontario Fair Hydro Plan Distribution Rate Protection Amount". The corresponding set-off is *charge type* 756 "MOE - Ontario Fair Hydro Plan Distribution Rate Protection Balancing Amount".

1.6.33.4 Intentionally Left Blank

Note:	The section 'Financing Entity' has been removed as per amendment to regulation. For more details, refer to Appendix E.13, where the archived section can be found.

1.6.33.5 Intentionally Left Blank

Note:	The section 'Regulatory Asset' has been removed as per amendment to regulation. For more details, refer to Appendix E.13, where the archived section can be found.

1.6.34 Capacity Exports[17]

A Capacity Seller is not eligible for any congestion management *settlement* credit payments in respect of an *energy* bid from a *boundary entity* for a *called capacity export*. The IESO may withhold or recover any congestion management *settlement* credits paid in respect of *called capacity exports* and will redistribute any recovered payments in accordance with Chapter 9, Section 4.8.2 of the *market rules*.

Refer to "Market Manual 9: Part 9.5: Settlement for the Day-Ahead Commitment Process" for details on DA-PCG *settlement amounts* for a Capacity Resource that has committed its capacity to an external *control area*.

Refer to "Market Manual 4: Market Operations Part 4.6: Real-Time Generation Cost Guarantee Program" for details on RT-GCG *settlement amounts* for a Capacity Resource that has committed its capacity to an external *control area*.

1.6.35 Dispute Resolution Settlement

After the successful resolution of a dispute between the IESO and a *market participant*, any *settlement amount* due to or owed by the market participant will be settled under *charge type* 700 "Dispute Resolution Settlement Amount" on the *settlement statements* for the last *trading day* of a subsequent month.

[17] Capitalized terms in Section 1.6.33 are defined in Market Manual 13.1: Capacity Export Requests, Appendix A: Glossary of Capacity Export Terms

The dispute resolution *settlement amount* will be fully balanced by one of the following, depending on the nature of the dispute and the associated resolution:

- Charge type 750 "Dispute Resolution Balancing Amount (IESO)", which will be due to or owed by IESO Adjustment Account; or
- Charge type 1750 "Dispute Resolution Balancing Amount (Market)", which will be due to or owed by market participants as a volumetric uplift charge based on load and export quantities.

1.6.36 COVID-19 Energy Assistance Program (CEAP and CEAP-SB)

The COVID-19 Energy Assistance Program was established by the Ministry of Energy, Northern Development and Mines as an expansion of the Low Income Energy Assistance Program (LEAP) to provide assistance to residential customers, small business customers, and registered charities who are struggling to pay their energy bills or are in arrears on their bills as a result of COVID-19. This program has been extended for the fiscal year 2021-22 by the ENDM - see "1.6.36.3 COVID-19 Energy Assistance Program 2021-22 (CEAP 2021-22)" and the letter, "OEB CEAP and CEAP-SB Funding Allocation". The Ministry has entered into a transfer agreement with the *IESO* to reimburse, up to a cap specified by the OEB, licensed *distributors* and unit sub-meter providers for CEAP credits that they have provided to consumers that have eligible accounts with: the licensed *distributor*; and wholly-embedded distributors of which the licensed *distributor* is the host distributor; and unit sub-meter providers that are serving residential customers under CEAP and small business customers and registered charities under CEAP-SB.

Licensed *distributors* and unit sub-meter providers registered with the *IESO* must submit their claims for reimbursement to the *IESO* monthly on a monthly basis no later than the fourth *business day* after the last *trading day* of the month. The *settlement amount* for licensed *distributors* and unit sub-meter providers will be included on the *settlement statement* for the last *trading day* of the month in which the claims were processed.

1.6.36.1 Settlement of COVID-19 Energy Assistance Program (CEAP) Claims

In order to maximize the ability of CEAP to provide the intended benefits, the OEB has determined that CEAP must be available to residential electricity customers prior to the end of the winter disconnection ban July 31. Therefore, license *distributors* and unit sub-meter providers must start accepting applications for CEAP as of July 13, 2020.

Licensed *distributors* and unit sub-meter providers must submit their CEAP forms to *IESO* via the settlement form "COVID-19 Energy Assistance Program".

The CEAP *settlement amount* for licensed *distributors* and unit sub-meter providers will be included on the *settlement statement* for the last *trading day* of the month under *charge type* 1477 "COVID-19 Energy Assistance Program (CEAP) Settlement Amount".

The corresponding set-off is *charge type* 9984 "COVID-19 Energy Assistance Program (CEAP) Balancing Amount" on the Ministry's *settlement statements*.

1.6.36.2 Settlement of COVID-19 Energy Assistance Program – Small Business (CEAP-SB) Claims

Licensed *distributors* and unit sub-meter providers must submit their CEAP-SB claims to *IESO* via the settlement form "COVID-19 Energy Assistance Program – Small Business".

The CEAP-SB *settlement amount* for licensed *distributors* and unit sub-meter providers will be included on the *settlement statement* for the last *trading day* of the month under *charge type* 1477 "COVID-19 Energy Assistance Program (CEAP) Settlement Amount".

The corresponding set-off is *charge type* 9984 "COVID-19 Energy Assistance Program (CEAP) Balancing Amount" on the Ministry's *settlement statement*.

1.6.36.3 COVID-19 Energy Assistance Program 2021-22 (CEAP 2021-22)

The *IESO* will begin accepting CEAP 2021-22 submissions by licensed *distributors* and unit sub-meter providers beginning May 1, 2021.

Licensed *distributors* and unit sub-meter providers must submit their residential and small business claims to *IESO* via the settlement form "COVID-19 Energy Assistance Program 2021-22".

The CEAP 2021-22 *settlement amount* for licensed *distributors* and unit sub-meter providers will be included on the *settlement statement* for the last *trading day* of the month under *charge type* 1477 "COVID-19 Energy Assistance Program (CEAP) Settlement Amount".

The corresponding set-off is *charge type* 9984 "COVID-19 Energy Assistance Program (CEAP) Balancing Amount" on the Ministry's *settlement statement*.

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2. Procedural Work Flow

The diagrams in this section represent the flow of work and information related to the *physical markets settlement statement* procedure between the *IESO* and *market participants*.

Table 2–1: Legend for Work Flow Diagrams

Legend	Description
Oval	An event that triggers task or that completes task. Trigger events and completion events are numbered sequentially within procedure (01 to 99)
Task Box	Shows reference number, party responsible for performing task (if "other party"), and task name or brief summary of task. Reference number (e.g., 1A.02) indicates procedure number within current *market manual* (1), sub-procedure identifier (if applicable) (A), and task number (02)
Solid horizontal line	Shows information flow between the *IESO* and external parties
Solid vertical line	Shows linkage between tasks
Broken line	Links trigger events and completion events to preceding or succeeding task

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2.2 Designating Facility for Generation Station Service or Electricity Storage Station Service Rebate

Metered market participants must apply for the designation of *generation facility* or *electricity storage facility* as eligible for the Generation Station Service and Electricity Storage Station Service Rebate. The steps in Figure 2-3 illustrate the process for designating a *generation facility* or *electricity storage facility* as eligible for Generation Station Service Rebate or Electricity Storage Station Service Rebate, and are described in detail in Section 3.3, Table 3-3.

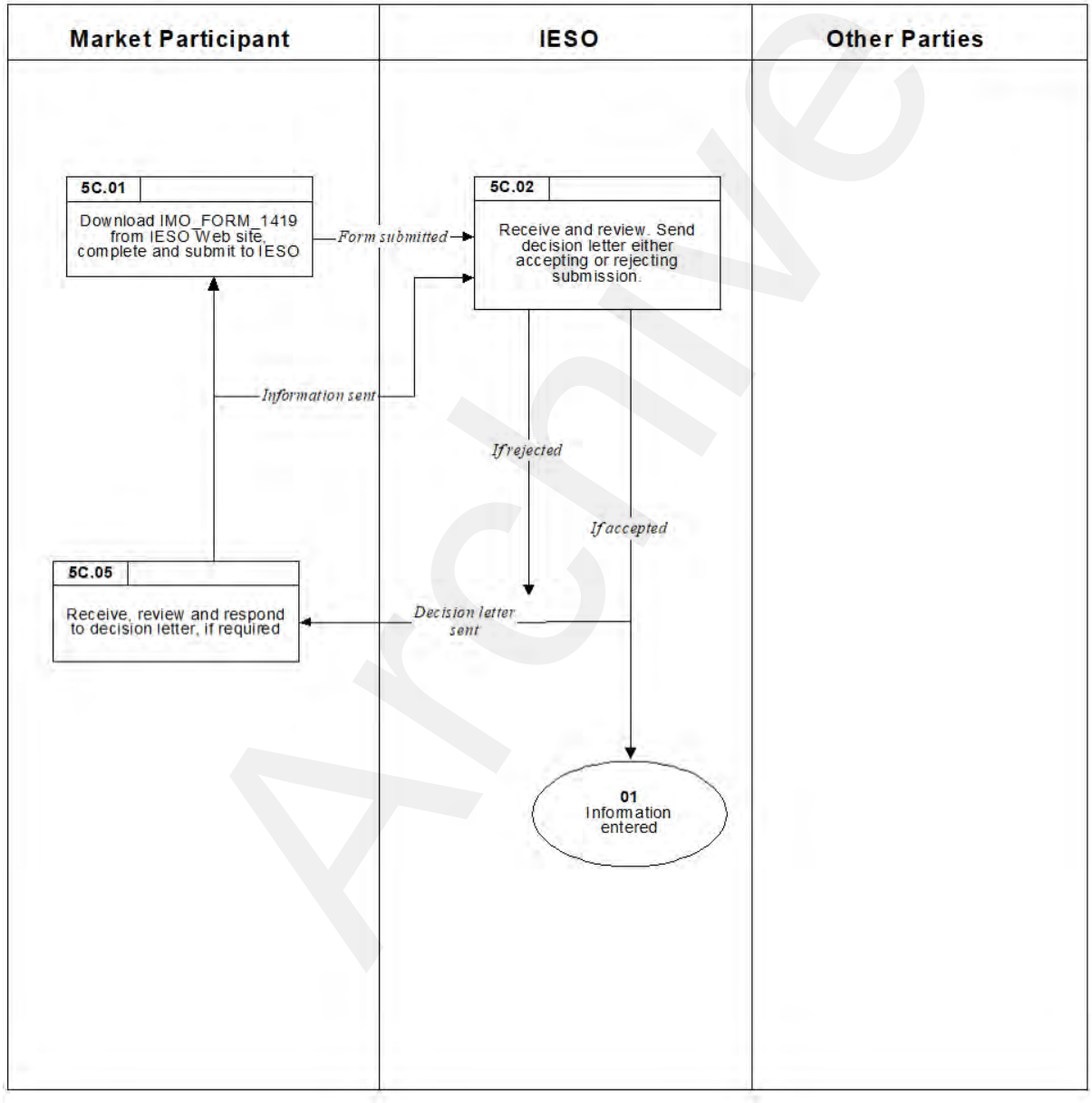


Figure 2–3: Work flow for Designating Facility for Generation Station Service Rebate

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2.8 Declaration of Designated Consumer

If you meet the criteria for a 'designated consumer', as defined in "Bill 4 *An Act to amend the Ontario Energy Board Act 1998 with respect to energy pricing*" and regulations, you must make a declaration to us. The steps in Figure 2-9 illustrate the process for notifying us of such an assignment(s) and are described in detail in Section 3.9, Table 3-9.

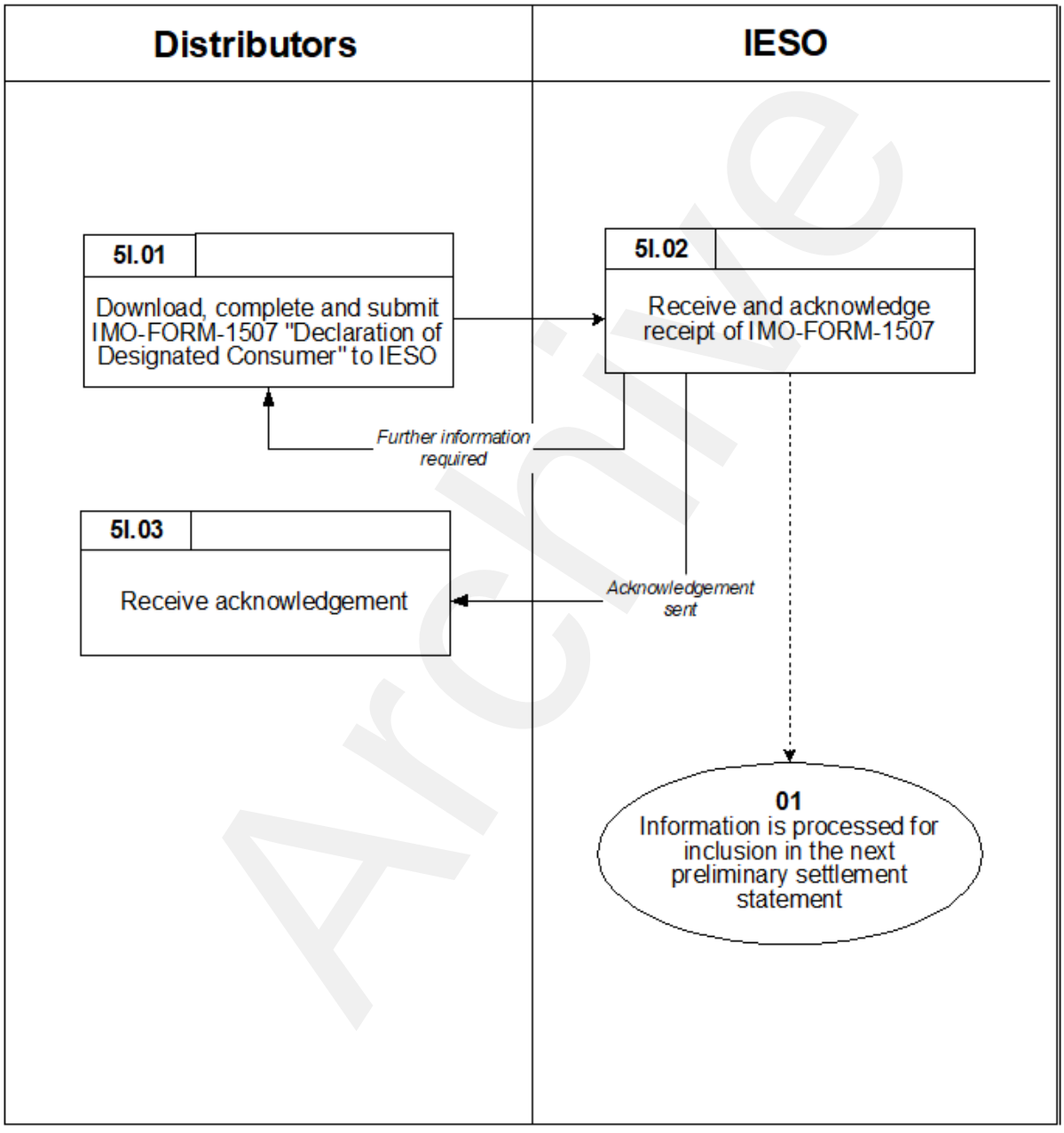


Figure 2–9: Work flow for Declaration of Designated Consumer

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Figure 2–10: Intentionally Left Blank

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2.10 Submitting Transmission Service Charges for Embedded Generation

Annually, *transmission customers* must, for each *embedded generation facility* for which a *metering point* has been registered under the Alternative Metering Installation Standards for Embedded Generation Facilities (Chapter 6, Section 4.5 of the *market rules*), submit annual adjustment dollar values for the applicable *transmission service charges*. Submit via Online IESO within three months of the calendar year end. If we do not receive this information in a timely manner, we will use the installed *maximum continuous rating* (as registered) for the *embedded generation facilities* to determine an adjustment amount. The steps in Figure 2-11 illustrate the process for notifying us of such an assignment(s) and are described in detail in Section 3.11, Table 3-11.

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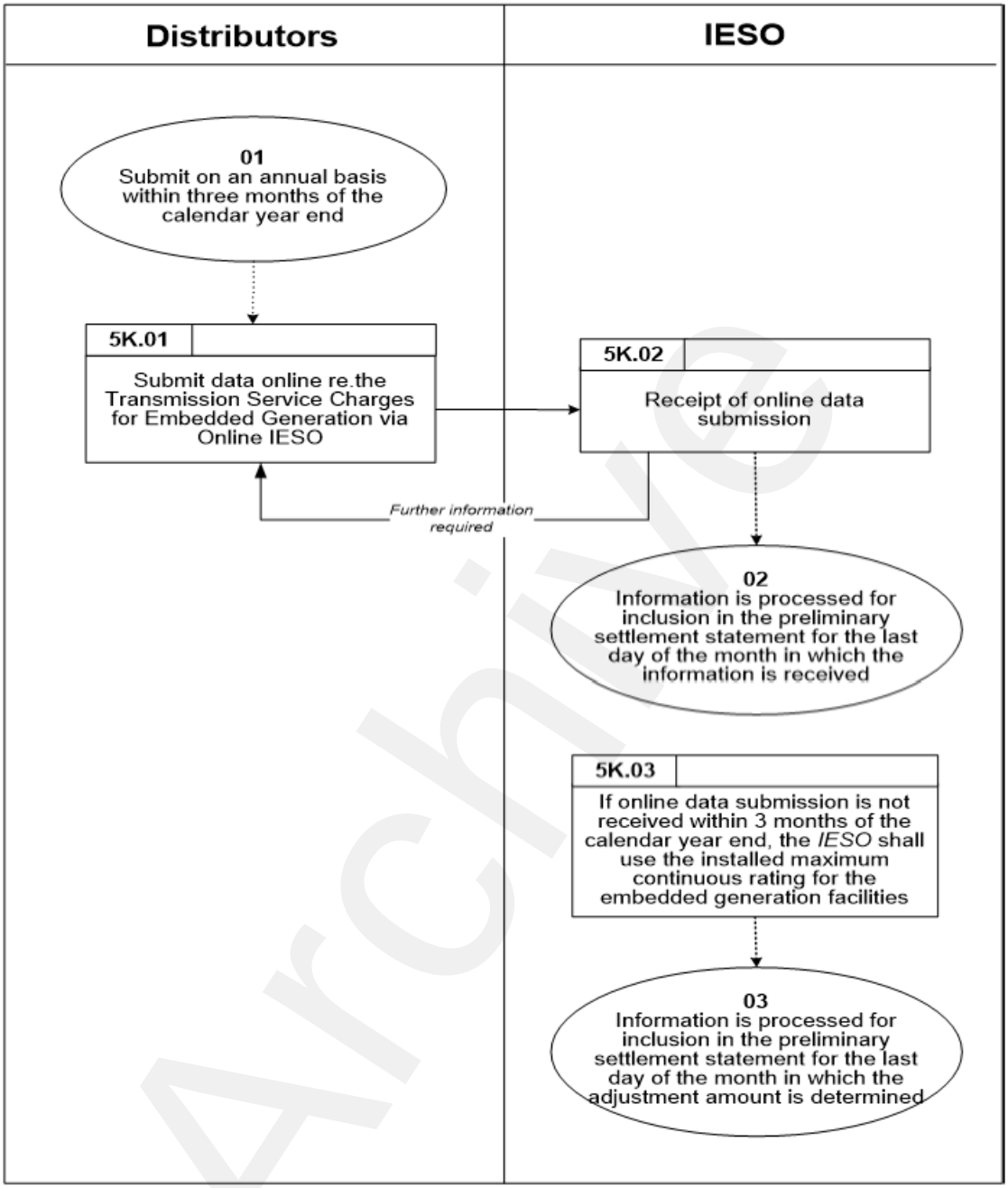


Figure 2–11: Work flow for Submitting of Transmission Service Charges for Embedded Generation

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2.11 Workflow for Submitting NUG Adjustment Amount Information

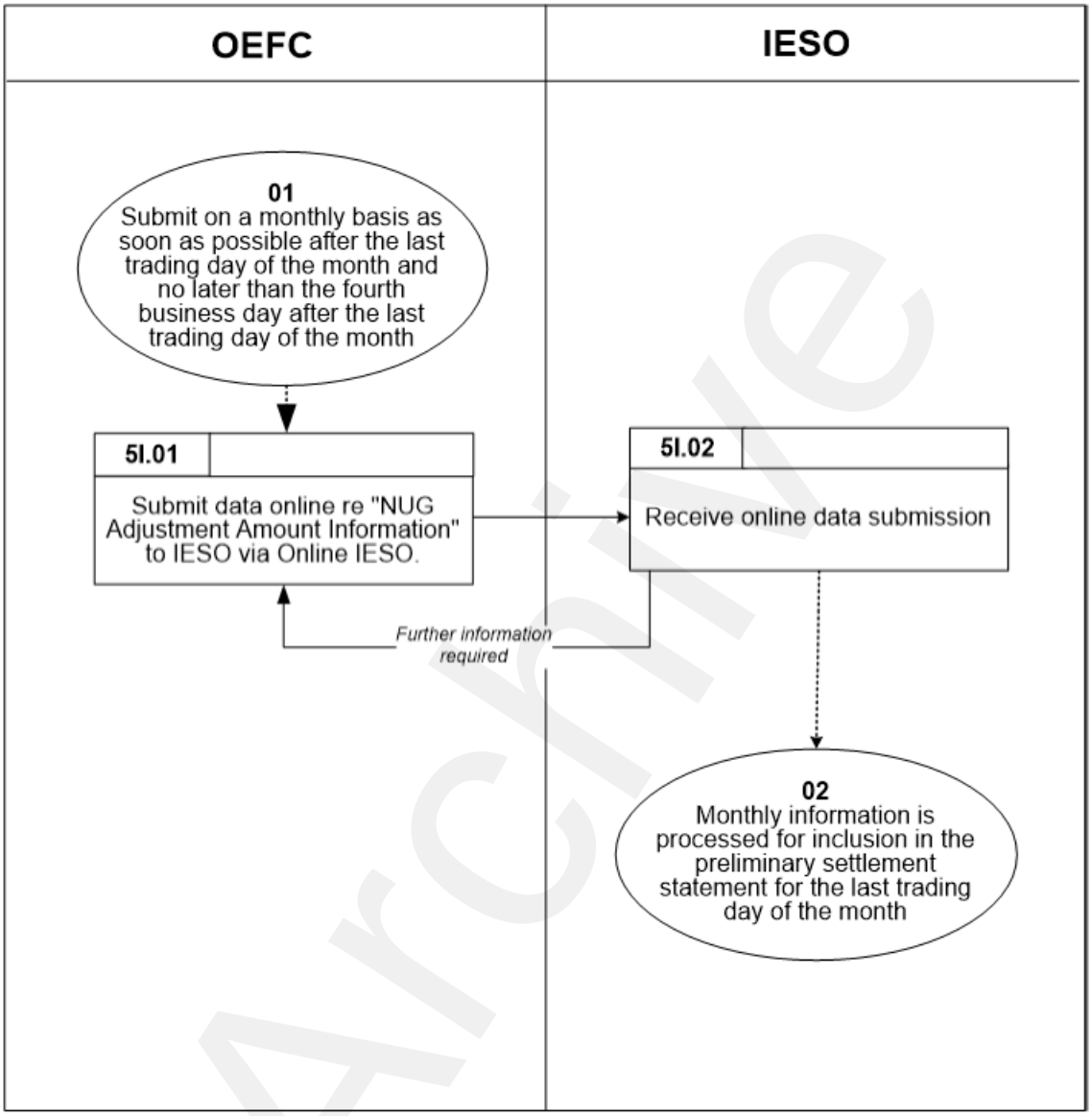


Figure 2–12: Workflow for Submitting NUG Adjustment Amount Information

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2.12 Workflow for Submitting Embedded Generation and Regulated Price Information

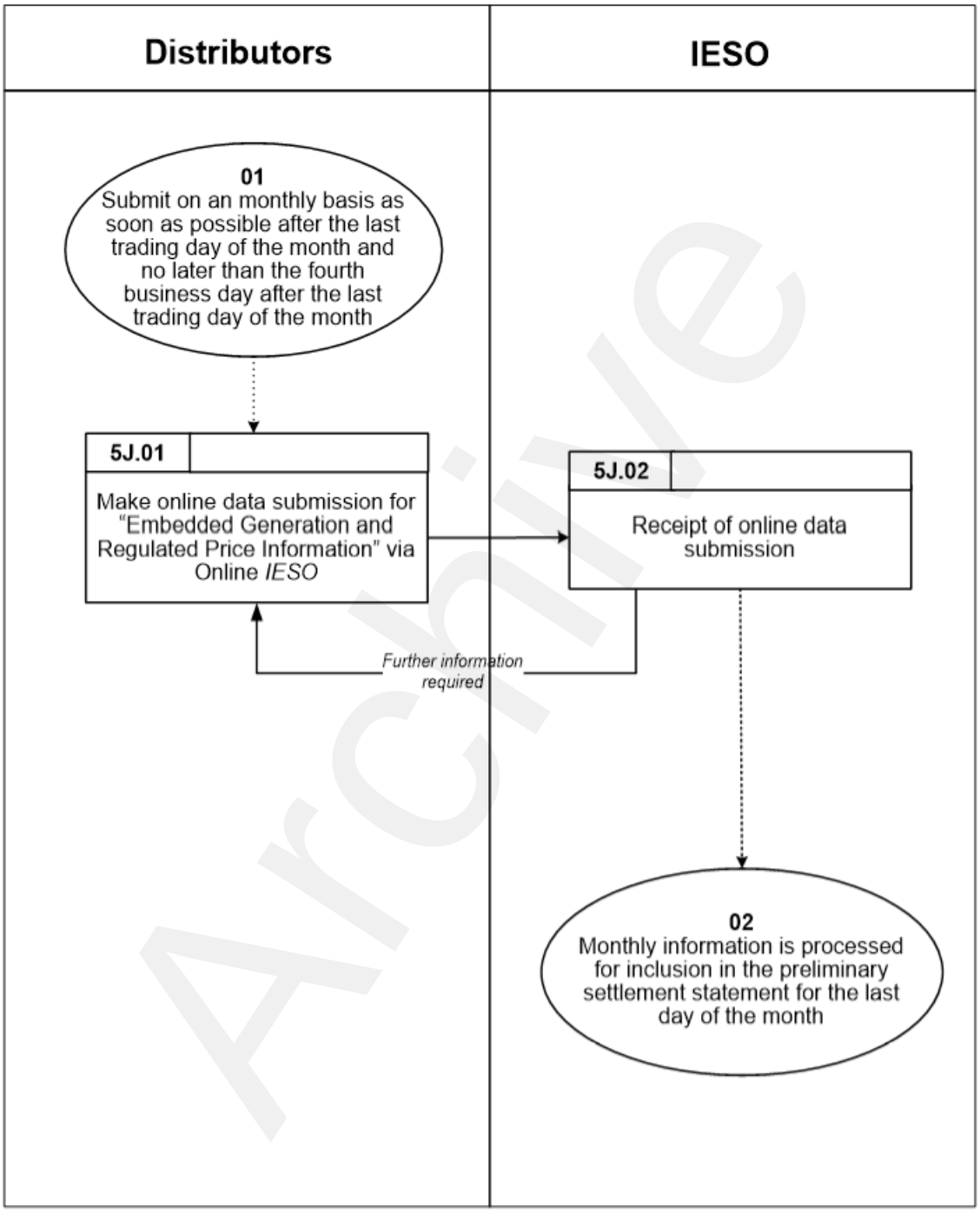


Figure 2–13: Workflow for Submitting Embedded Generation and Regulated Price Information

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3. Procedural Steps

This section contains detail on the tasks (steps) that comprise the *settlement statements* procedure. The steps in the following tables are illustrated in Section 2.

The tables contain seven columns, as follows:

Ref

The numerical reference to the task.

Task Name

The task name as identified in Section 2.

Task Detail

Detail about the task.

When

A list of all the events that can trigger the task to begin.

Resulting Information

A list of the information flows that may or must result from the task.

Method

The format and method for each information flow.

Completion Events

A list of all the circumstances in which the task is considered complete.

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3.3 Designating Facility for Generation Station Service Rebate or Electricity Storage Station Service Rebate

Metered market participants should retrieve IMO_FORM_1419 "Application for Designation of a Facility for Generation Station Service Rebate" in order to apply for a rebate. The steps shown in the following table are illustrated in Section 2.3, Figure 2-3.

Table 3–3: Procedural Steps for Designation of Facility for Generation Station Service Rebate and Electricity Station Service Rebate

Ref.	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
5C.01	Download IMO_FORM_1419 from our web site, complete and submit to us.	*Metered market participant* downloads "Application for Designation of a Facility for Generation Station Service Rebate" (IMO_FORM_1419) from our web site. The *metered market participant* completes the form and submits it to us.	When the *metered market participant* believes a *generation facility* or *electricity storage facility* is eligible for rebate of *generation station service* or *electricity storage station service*	*Metered market participant* has applied for designation of a *facility* as eligible for rebate of *generation station service* or *electricity storage station service*	Fax, mail or courier.	Form submitted.
5C.02	Receive and review. Send decision letter either accepting or rejecting submission.	We receive, review and send a letter to the *metered market participant* indicating whether the submission is complete or information is required (acceptance or rejection).	After Step 5C.01.	Application for designation of a *facility*.	Fax.	Form received and reviewed. A decision letter is sent to the *metered market participant* either accepting or rejecting the submission.

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Ref.	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
5C.03	Receive, review and respond to decision letter, if required.	*Metered market participant* receives and reviews our decision. If more information is required, the *metered market participant* resubmits the application.	After receiving the decision letter.	None.	Fax, if required.	*Metered market participant* received letter accepting or rejecting designation for *generation station service* rebate or *electricity storage station service* rebate.

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3.9 Declaration of Designated Consumers

Market participants meeting the 'designated consumer' criteria (as defined in "Bill 4 *An Act to amend the Ontario Energy Board Act, 1998 with respect to energy pricing*" and the regulations) may inform us of this.

The steps shown in the following table are illustrated in Section 2.9, Figure 2-9.

Table 3–9: Procedural Steps for Declaration of Designated Consumers

Ref.	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
5I.01	Download, complete and submit IMO_FORM_1507 "Declaration of Designated Consumer" to us.	*Market participants* download IMO_FORM_1507 from our web site, complete the Form and submit it to us. The sender ensures the proper signatures are included.	As a *market participant* becomes eligible.	Declaration of designated consumer is made.	Email, followed by Fax with signature of signing authority.	Declaration information is sent to us.
5I.02	Receive and acknowledge receipt of IMO_FORM_1507.	We receive and send an acknowledgement of receipt of the IMO_FORM_1507 from eligible *market participants*. In the event further information is required, the *market participant* is requested to re-submit the form.	Upon receipt of information.	Acknowledgement.	Email.	Information received by us and acknowledgement sent to *market participant.*
5I.03	Receive acknowledgement.	*Market participants* receive acknowledgement of our receipt of IMO_FORM_1507.	After step 5I.02.	None.	Email.	Acknowledgement received.

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Table 3–10: Intentionally Left Blank

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3.11 Submitting Transmission Service Charges for Embedded Generation

For each *embedded generation facility* for which a *metering point* has been registered under the Alternative Metering Installation Standards for Embedded Generation Facilities (Chapter 6, Section 4.5 of the *market rules*) *transmission customers* will submit adjustment dollar values for the applicable *transmission service charges*. *Settlement* data must be submitted via Online IESO within three months of the calendar year end. In the event that the *IESO* does not receive this information in a timely manner, we will use the installed *maximum continuous rating* (as registered) for the *embedded generation facilities* to determine an adjustment amount.

Steps shown in the following table are illustrated in Section 2.11, Figure 2-11.

Table 3–11: Procedural Steps for Submission of Transmission Service Charges for Embedded Generation

Ref.	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
5K.01	Submit Transmission Service Charges for Embedded Generation online via Online IESO.	*Transmission Customers* submit information via the Submit Settlement Claim action available through Online IESO. Line and Transformation Connection Service Charges need to be calculated for all *delivery points* with *embedded generation facilities* registered under the Alternative Metering Installation Standards for Embedded Generation Facilities. The sender ensures adjustment amounts are agreed to by the *transmitter*.	Annually, as soon as possible after the last day of the calendar year and no later than three months after calendar year end.	Annual adjustment dollar values for the applicable *transmission service charges* associated with *embedded generation facilities* registered under the Alternative Metering Installation Standards for Embedded Generation Facilities.	Submitted via Online IESO.	Annual adjustment information is sent to us.

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Ref.	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
5K.02	Receipt of online data submission.	We receive the online data submission from *transmission customers*. In the event further information is required, the *distributor* is requested to re-submit the form.			*Online IESO*.	Information received by us.
5K.03	If the online data submission is not received within 3 months of the calendar year end, we will use the installed *maximum continuous rating* for the embedded *generation facilities*.	In the event that we do not receive a data submission within three months of the calendar year end, We will use the installed *maximum continuous rating* for the *embedded generation facilities* (provided to us at the time of the *meter point* registration) to calculate the applicable *transmission service charges*.	Annually, as soon as possible after the expiration date (three months after calendar year end) for *transmission customer* submissions has expired.	Annual adjustment dollar values for the applicable *transmission service charges* associated with *embedded generation facilities* registered under the Alternative Metering Installation Standards for Embedded Generation Facilities	Internal *IESO* calculation.	Annual adjustment information is calculated by us.

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3.12 Submitting NUG Adjustment Amount Information

Each month, *OEFC* submits information to the *IESO* for the difference between NUG contract costs and wholesale market payments for NUGs.

Steps shown in the following table are illustrated in Section 2.12, Figure 2-12.

Table 3–12: Submission of NUG Adjustment Amount Information

Ref.	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
5I.01	Submit "NUG Adjustment Amount Information" via Online IESO.	*OEFC* submits information via the Submit Settlement Claim action available through Online IESO.	Within four *business days* after the last *trading day* of every month.	Monthly adjustment for any differences between the contract price for NUG output and the *market price* for NUG output for the previous month. Monthly forecast NUG rate in $/MWh for the current month. Monthly forecast NUG production in MW for the current month.	Online *IESO*.	Declaration information is sent to us.
5I.02	Receipt of online data submission.	We receive the online data submission from *OEFC*. In the event further information is required, the *OEFC* is requested to re-submit the data.	Upon receipt of information.	Acknowledgement.	Online *IESO*.	We receive information.

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3.13 Submitting Embedded Generation and Regulated Price Information

Each month, *distributors* submit information to us for residual differences between the regulated price and the wholesale *market price* plus global adjustment for regulated *consumers* within the *distribution system*. The *distributor* also must submit information provide by *retailers* and embedded *distributors*.

Steps shown in the following table are illustrated in Section 2.13, Figure 2-13.

Table 3–13: Procedural Steps for Submission of Embedded Generation and Regulated Price Information

Ref.	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
5J.01	Submit data for Embedded Generation and Regulated Price Information via Online IESO.	*Distributors* submit information online via the Submit Settlement Claim action available through Online IESO. *Distributors* enter amounts for various differences to make them and the following agents whole: •Embedded *distributors*, •Participating *retailers* using *distributor*-consolidated billing, •Participating *retailers* using retailer-consolidated billing. *Distributors* must report embedded generation and distribution to Class A *consumers*.	Within four *business days* after the last *trading day* of every month.	Monthly adjustments for any differences between: • the regulated price and *market price* plus global adjustment for regulated *consumers*; • the *market price* and contract price for participating *retailers* with *distributor*-consolidated billing; • the regulated price and contract price for participating *retailers* with *retailer*-consolidated billing; and	Submitted via Online *IESO*.	Monthly adjustment information is sent to us.

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Ref.	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
				• the daily global adjustment and the monthly global adjustment. Monthly amount distributed to Class A *consumers* for the previous month and forecast amount of embedded generation distributed to Class A *consumers* for the current month.		
5J.02	Receive online data submission.	We receive the *settlement* data submitted online from *distributors* via Online IESO. In the event further information is required, the *distributor* is requested to re-submit via Online IESO.			Online *IESO*.	Information received by the *IESO*.

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Appendix A: Forms

This appendix contains a list of forms used in the *physical markets settlement statements* process, which are available on the *IESO* Web site (http://www.ieso.ca). The forms included are as follows:

Form Name	Form Number
Application for Designation of a Facility for Generation Station Service Rebate	IMO_FORM_1419
Declaration of Designated Consumer	IMO_FORM_1507
Administrative Pricing Event Correction	IMO_FORM_1549

Note: *Electricity storage participants* are required to use the above forms. These forms are expected to be updated if and as necessary to include language specific to *electricity storage facilities* and *electricity storage participants*. Until such time, any questions from *electricity storage participants* relating to how to fill out the forms correctly may be addressed by IESO Customer Relations.

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Appendix C: IESO Charge Types Applicable to the Authorized Charge

Note: The provisions of this appendix do not apply for any period beginning after March 31, 2005. The provisions of this appendix have been retained in the event that a re-calculation of the *energy* uplifts for any period prior to April 1, 2005 is necessary.

This appendix contains a list of *IESO charge types* included in the authorized charge defined in "Ontario Regulation 436/02". This set of charges is derived from the "IESO Charge Types and Equations" excluding:

- charges that are payable as defined by "Ontario Regulation 436/02 2(3)" (commodity charge, the *Debt Retirement Charge* and the *Transmission Services Charges*);
- charges identified by the Ontario *Energy* Board (deemed non-recurrent wholesale market service charges);
- charges payable to *market participants*;
- charges applicable to specific participants for products supplied to us; and
- charges not active in the market.

Table C–1: IESO Charge Types Included in the 0.62 Monthly Calculation

Charge Type Number	Charge Type Name
0150	Net Energy Market Settlement Uplift
0155	Congestion Management Settlement Uplift
0168	TR Market Shortfall Debit
0170	Local Market Power Rebate
0182	Hour-Ahead Dispatchable Load Offer Guarantee
0183	Generation Cost Guarantee Recovery Debit
0184	Demand Response Debit
0250	10 Minute Spinning Market Reserve Hourly Uplift
0252	10 Minute Non-Spinning Market Reserve Hourly Uplift
0254	30 Minute Operating Reserve Market Hourly Uplift
0450	Black Start Capability Settlement Debit
0452	Reactive Support and Voltage Control Settlement Debit
0454	Regulation Service Settlement Debit
0550	Must-Run Contract Settlement Debit
0753	Rural Rate Settlement Charge
9990	IESO Administration Charge

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Appendix D: Price Bias Adjustment Factors Calculation Method for the Real-Time Import and Export Failure Charge

The real-time failure charge calculation for imports and exports includes the difference between the pre-*dispatch* and the real-time Ontario *energy* prices during the hour of the failure. Including transaction failures, there are many factors that contribute to the pre-*dispatch* to real-time price differences. The purpose of the price bias adjustment factors is to adjust this charge by the forecast value of the difference between the pre-*dispatch* and the real-time Ontario *energy* price that is due to the systematically caused differences (C. 9, S. 3.8C.7).

The following methodology does not specifically isolate the price difference due to the systematic differences, but we will use it as a proxy until we are technically able to isolate this contribution or improve on the present methodology to meet this goal.

We provide these price bias adjustment factors to help you assess your exposure to the *settlement* charge for the upcoming *settlement* periods.

The following calculation method produces twenty-four hourly factors that apply for a three-month period. These three-month periods are aligned with the seasons. New factors will apply to the next calendar year.

The periods are:

- the winter factors apply to December, January, and February;
- the spring factors apply to March, April, and May;
- the summer factors apply to June, July, and August; and
- the autumn factors apply to September, October, and November.

Effective time for each three-month block starts at the first hour of the first day of the month and ends at the twenty-fourth hour of the last day of the third month in the block.

We use the following methodology to calculate the price bias adjustment factors:

Data Set

The total data set used to calculate the price bias adjustment factors includes all pre-*dispatch* to real-time Ontario *energy* price differences, including those differences which are zero, positive, and negative. This total data set includes all differences from the start of the Ontario market (May 1, 2002) until the present calendar year.

We calculate the price bias adjustment factors using a subset of the total data set. All the price differences are divided into those which occurred in each hour of the day during each seasonal block defined above. The price bias adjustment factors are calculated using the corresponding hours in the corresponding months. For example, the spring factor for hour 1 is calculated using all the price differences from hour 1 for the months of March, April, and May of each year since market opening. This results in data sets that are hourly, seasonal, and yearly.

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Frequency distributions for these data sets are created. We determine the median values of the frequency distributions. The median value is defined as the middle value of this distribution. More specifically, there are the same numbers of observations to the left and to the right of the median value of the frequency distribution.

Weighting Factors

Each yearly median value is assigned a weighting factor from 0 to 1. A year with a weighting factor of zero results in that year's median value not contributing to the determination of the price bias adjustment factor. Conversely, a year assigned a weighting factor of 1 will solely be considered at the exclusion of all other years. After taking into account the weighing factors, we determine a price bias adjustment for each hour of the day for a three month block.

The use of weighing factors allows us to establish the best forecast by enabling the price bias adjustment factors to reflect short term and long term influences on the pre-*dispatch* to real-time Ontario *energy* price differences. The weighting factor assignments are at our discretion.

These calculations result in twenty-four hourly price bias adjustment factors for each season of the year. These factors are the same for the import and export *settlement* charge.

We will post the price bias adjustment factors on our web site in advance of their effective *trading day*.

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Appendix E: Expired Settlement Calculations Kept for Purposes of Re-Calculation

E.1 Fixed Energy Rate Program

Note: The provisions of this section do not apply for any period beginning after March 31, 2005. The "Electricity Restructuring Act, 2004" (also referred to as Bill 100) replaced the Fixed Energy Rate Program described below, with *charge types* 140/190 being replaced by *charge types* 142/192. The provisions of this section have been retained in the event that a re-calculation of the *energy* rate for any period prior to April 1, 2005 is necessary.

"Bill 4 An Act to amend the *Ontario Energy Board Act, 1998*" with respect to electricity pricing and regulations passed pursuant to "Bill 4", fix the commodity price for *energy* at 4.7 cents per kilowatt hour up to and including 750 kWh per month and 5.5 cents per kilowatt hour in excess of the 750 kWh (net of any *energy* purchased under *physical bilateral contracts*) (uncovered *energy*) for "low-volume *consumers*" and "designated *consumers*" (as defined in "Bill 4"). A fixed *energy* rate will not take the place of the *hourly Ontario energy price (HOEP)* or *energy market price* (EMP) for existing calculations. The fixed *energy* rate will be implemented via a supplementary process which consists of a calculation of the offset necessary to adjust the commodity price to the equivalent of 4.7 cents per kilowatt hour up to and including 750 kWh per month and 5.5 cents per kilowatt hour in excess of the 750 kWh. This offsetting amount is included as a new item on *preliminary* and *final settlement statements* and monthly *invoices* under *charge type* 140, "Fixed Energy Rate Settlement Amount". (Chapter 9, Sections 1.2.1 and 1.2.2 of the *market rules*)

All charges associated with *charge type* 140 require a corresponding off-set *charge type* in order to balance the market. This corresponding new *charge type* 190 "Fixed Energy Rate Balancing Amount" will be debited or credited to the Ontario Electricity Financial Corporation (*OEFC*). (Refer to "IESO Charge Types and Equations" and "Format Specifications for Settlement Statement Files and Data Files", located on the Technical Interfaces page of the *IESO* Web site, for details of these *charge types*.) *Market participants' settlement statements* will reflect additions of new Manual Line Items as detailed in these two new *charge types*.

E.1.1 Declaration Required for Designated Consumers

A 'designated consumer' has been defined in "Bill 4" and "Regulations 435/02, 43/04 and 433/02". Wholesale *market participants* who qualify as 'designated consumers' must inform us by completing and submitting a declaration using IMO_FORM_1507 "Declaration of Designated Consumer" located on our web site. *Market participants* who satisfy us that they qualify as designated consumers will be settled at the fixed *energy* rate of 4.7 cents per kilowatt hour up to and including 750 kWh per month and 5.5 cents per kilowatt hour in excess of the 750 kWh and a fixed 0.62 cents per kWh for the designated charges prescribed by government regulation (described in Section E.2 below).

E.1.2 IESO Market Participants that are Low-Volume or Designated Consumers

Fixed *energy* rate adjustments for eligible *market participants* covered under *charge type* 140 apply to net *energy* withdrawals, not covered by a *physical bilateral contract,* from the *IESO-administered market*. The net *settlement amount* results in an effective rate equivalent to the fixed price for all eligible uncovered *energy* transactions. Eligible *market participants' settlement statements* will be adjusted as follows:

- CRS will create a 140 detailed (DP) record that is incorporated in the *settlement statement* that will, together with the 101 detailed (DP) record, apply an effective fixed rate of 5.5 cents per kWh; and
- a manual adjustment is applied at the end of the month to apply a rate of 4.7 cents per kWh for *energy* withdrawals up to 750 kWh.

E.1.3 Distributor Claims

Regulations have been passed that provide for month-end adjustments for *distributors*. The purpose of the adjustments will be to offset the differences that arise from *distributors* settling with us at the *market price* and charging 4.7 cents per kilowatt hour up to and including 750 kWh per month and 5.5 cents per kilowatt hour in excess of the 750 kWh to low-volume *consumers* and designated *consumers*.

Eligible *distributors* that are *market participants* must submit the relevant information to us using IMO_FORM_1562 "Bill 4 Submission of Information Required for Monthly Fixed Prices" denoting the amount of the claim for each category. This form is used for all the information required from the *distributor*, embedded *distributor*[18] or participating *retailer*[19] to balance the market. IMO_FORM_1562 must be submitted on a monthly basis to us as soon as possible after the last *trading day* of the month and no later than the fourth *business day* after the last *trading day* of the month. We process this information so that the *preliminary settlement statement* for the last *trading day* of the month will indicate a *charge type* 140 entry with the Comments field noting the relevant category as follows:

- adjustment for low-volume and designated *consumers* billed by a *distributor*;
- adjustment for low-volume and designated *consumers* supplied by embedded generation billed by a *distributor*;
- adjustment for low-volume and designated *consumers* billed by an embedded *distributor*;
- adjustment for low-volume and designated *consumers* supplied by embedded generation billed by an embedded *distributor*;
- adjustment for participating *retailers* using *distributor*-consolidated billing;
- adjustment for participating *retailers* using *distributor*-consolidated billing, within an embedded *distributor*;
- adjustment for participating *retailers* using *retailer*-consolidated billing; and
- adjustment for participating *retailers* using *retailer*-consolidated billing, within an embedded *distributor.*

[18] "Embedded *distributor"* is classified by regulation, where it is assumed to take the meaning described in the *OEB* "Retail Settlement Code".

[19] Ibid.

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E.1.4 Opt Out Provisions

Eligibility of *market participants* to opt out of the Fixed Energy Rate Program is based on the following provision:

- directly-*connected* load-consuming *market participants* meeting the regulated definition of "low-volume *consumers*" or "designated *consumers*" may opt out of the Fixed Energy Rate Program for all *registered facilities* for which they play the role of a *metered market participant* provided they have interval *metering*.

Market participants must inform us in writing if they wish to exercise this option.

E.2 Authorized Charge for the Operation of the IESO-Administered Markets

Note:	The provisions of this section do not apply for any period beginning after March 31, 2005, as their operation expired as of that date. Accordingly, *charge types* 141 & 191 are no longer applicable for any such period. The provisions of this section have been retained in the event that a re-calculation of the authorized charge for any period prior to April 1, 2005 is necessary.

Effective December 2002, "Regulation 436/02" establishes a fixed charge of 0.62 cents per kWh for the operation of the *IESO-administered markets*, operation of the *IESO-controlled grid* and the rate protection provided under Section 79 of the "*Ontario Energy Board Act, 1998*" for rural and remote *consumers* (defined as the 'authorized charge'). The authorized charge applies to *distributors,* low-volume *consumers* and designated *consumers* who are *market participants*. The relevant *IESO charge types* (refer to Appendix C: "IESO Charge Types Applicable to the Authorized Charge") will continue to appear on daily *settlement statements* in the usual manner. On the *preliminary* and *final settlement statement* for the last *trading day* of the month, we will total these specified charges and apply an adjustment for the month to ensure that the authorized charge of 0.62 cents per kWh has been applied for all AQEW.

The authorized charge is applied to *settlement statements* as follows:

- CRS will calculate a monthly value that is incorporated into *preliminary* and *final settlement statements* for the last *trading day* of the month as detailed (DP) records.

Distributors are required to submit to us the wholesale market charges associated with the *energy* purchased from *embedded generators*. Again, IMO_FORM_1562 "Bill 4 Submission of Information Required for Monthly Fixed Prices" must be submitted on a monthly basis to us as soon as possible after the last *trading day* of the month and no later than the fourth *business day* after the last *trading day* of the month.

The adjustment to the uplift charges will appear on the *settlement statements* for the last *trading day* of each month. This offsetting amount is included as a new item on *settlement statements* and *invoices* under *charge type* 141 "Fixed Wholesale Charge Rate Settlement Amount".

All charges associated with *charge type* 141 require a corresponding off-set *charge type* in order to balance the market. This corresponding new *charge type* 191 "Fixed Wholesale Charge Rate Balancing Amount" will be debited or credited to the Ontario Electricity Financial Corporation (*OEFC*). *Market participants' settlement statements* will reflect additions of new manual line items as detailed in these two new *charge types*.

E.3 OPA's Demand Response (DR3) Program[20]

The IESO implemented a contractual load reduction program for *market participants*, LDC-*connected* participants and aggregators who are capable of providing a net electricity load reduction of at least 5 MW and, for aggregators, 25 MW. Refer to the *OPA*'s DR3 Contract, Program Rules and related Manuals on their web site for full details.

This section sets out how the *IESO* settles the DR3 Program. To the extent of any inconsistency between the provisions of the DR3 Program rules and this section, the DR3 Program rules shall govern.

DR3 participants are paid a monthly Availability Payment for being available to reduce their load during the Hours of Availability and a Utilization Payment for their actual load *curtailment* when directed by us. Given that as a DR3 participant, you may have more than one DR3 Contract Schedule for a given Settlement Account; your payment will be based on the total Monthly Contracted MWs for all such DR3 Contact Schedules and the weighted average of each of the applicable rates.

The DR3 program also includes an Availability Over-Delivery Payment to encourage higher than contracted *demand* reduction in response to an Open Standby Notification.

Settlement payments are subject to Performance Set-Offs for both Availability and Utilization for failure to comply with DR3 Contract terms including:

- maintaining a Reliability Rate of at least 85% for each interval;
- confirming in a timely manner when required by us to do so; or
- confirming at least 85% of the Monthly contacted MW for a Confirmed Hour.

Additionally, DR3 participants will be subject to an Availability Payment Set-Off for:

- not being fully available for *curtailment*;
- any days that they declare a planned non-performance event; or
- failing to deliver *meter* data in a timely manner.

E.3.1 Settlement of Demand Response Payments

How Availability Payments Are Settled

Each month, you will receive an Availability Payment for each Settlement Account based on the Hours of Availability, Monthly Contracted MW and the Adjusted Availability Rate as described in the DR3 Contract. The Adjusted Availability Rate is the weighted average of the rates for all Contract Schedules for a given Settlement Account and adjusted for premium zones and discount zones.

We calculate Availability Payments once a month in the month following the contract month and apply them as a manual line item to the last *trading day* of the month following the contract month. We use *charge type* 1340 "On behalf of *OPA* for the DR3 Program - Availability Payment Settlement Amount" for Availability Payments to participants.[21]

Where you have multiple DR3 Contract Schedules at a given Settlement Account, these DR3 Contract Schedules are aggregated into one manual line item for *settlement* purposes.

[20] In this section, "you" refers to a DR3 participant.

[21] Refer to "IESO Charge Types and Equations" and "File Format Specification for Settlement Statement Files and Data files" located on the Technical Interfaces page of the IESO Web site for details of these *charge types*.

We recover availability payments through *charge type* 1390 "Demand Response 3 Availability Payment Balancing Amount".

How Availability Over-Delivery Payments Are Settled

When you receive an Open Standby Notification, you may respond to us that you are available to deliver more MWs or reduce load for a longer period than agreed to in your DR3 Contract Schedule. In this case, you are entitled to receive an Over-Delivery Payment for each over-delivery hour in a Contract Month.

In each hour, the Confirmed MWs are limited to the lesser of the Monthly Contracted MW plus 15 MW or 130% of the Monthly Contracted MW. In addition, the number of activations is limited to an additional 7 times if the Maximum Contract Hours is 100 and an additional 14 times if the Maximum Contract Hours is 200, for each calendar year.

We calculate Availability Over-Delivery Payments once a month in the month following the Contract Month and apply them as a manual line item to the last *trading day* of the month following the Contract Month.

We use *charge type* 1341 "On behalf of *OPA* for the DR3 Program - Availability Over-Delivery Payment Settlement Amount" for the monthly Availability Over-Delivery Payments to participants[22].

We recover Over-Delivery Payments through *charge type* 1391 "Demand Response 3 Availability Over-Delivery Balancing Amount".

How Utilization Payments Are Settled

You are paid for the amount of load reduction you actually provide for a DR3 activation for each Settlement Account based on the Actual Activated MWh and the Utilization Rate as described in the Contract.

The Actual Activated MWhs are the metered reduction for the Activation Period. We will calculate your load reduction and *settlement* from the data you submit, according to your M&V Plan. For load reduction payments, the total reduction cannot exceed the confirmed reduction for the period plus the lesser of an additional 15 MWh or 15% of the Activation MW per hour of the Activation Period. In addition, the number of activations is limited to an additional 7 times if the Maximum Contract Hours is 100 and an additional 14 times if the Maximum Contract Hours is 200, for each calendar year.

We calculate Utilization Payments once a month in the month following the contract month and apply them as a manual line item to the last *trading day* of the month following the contract month. We use *charge type* 1343 "On behalf of *OPA* for the DR3 Program - Utilization Payment Settlement Amount" for Utilization Payments to participants.[23]

Utilization Payments are not made when an Activation Notice is sent by us and you are using one of the Planned Non-Performance Events at the Settlement Account.

Utilization Payments are recovered through *charge type* 1393 "Demand Response 3 Utilization Payment Balancing Amount".

How We Process Your Meter Data

As part of the DR3 application, participants submit an M&V Plan for each Settlement Account. We calculate a Baseline for each and every Activation Hour. For DR3 participants that are not *IESO administered market participants*, we will use:

[22] Ibid

[23] Ibid

- your weekly retail revenue *meter* data submitted by 15:00 EST on the first *business day* of the following week; and
- revisions to the weekly data received by 15:00 EST on the last *business day* of the month following the completed contract month.

For DR3 participants that are *market participants*, we will use your revenue metering data that we've collected as part of our market *settlement process*.

The Baseline calculation may be adjusted using the measured *demand* prior to the *Curtailment* hour as described in Exhibit B of the DR3 Contract.

We verify the actual *metering data* against the M&V Plan and our calculations.

Calculating Performance Set-Offs

Delivery of your load reduction amount is subject to performance criteria. Performance criteria consist of:

1. **Reliability**: If you do not achieve an average reduction (Reliability Rate) during any 5-minute interval in the hour of at least 85% of the Activated MW, or if you are Not Fully Available for Curtailment you will be subject to reliability Performance Set-Offs. Performance Set-Offs for below-standard reliability applies to both availability and utilization payments whereas not being fully available for *curtailment* applies only to the availability payment.

   Calculating Your Reliability Rate:

   Due to the importance of reliable load reduction for assessing and managing the *IESO-controlled grid*, you are required to maintain a Reliability Rate for each Settlement Account of at least 85% for each interval of an Activation Hour. The Reliability Rate is calculated for each 5-minute interval and the rate for any interval cannot exceed 100%.

   For Settlement Accounts that include more than one contract schedule, your Reliability Rate is based on your actual *curtailment* as a percentage of the aggregated Activation MW.

2. **Timely Confirmation**: If a Confirmation is required by us and you do not submit or submit a Confirmation late, both availability and utilization payments are subject to set-offs. The severity of the set-off will depend on how late the Confirmation is received.

3. **Low Confirmation**: If the Confirmed MWs are less than 95% of the Monthly Contracted MW for a Confirmed Hour, a Performance Set-Off will be calculated for each confirmed hour. This Set-Off will apply even if the actual load reduction is equal to or greater than the Monthly Contracted MW.

If more than one of the set-offs listed above apply to a Settlement Account, only the highest availability set-off amount shall be applied against your availability payment and similarly, only the highest Utilization Set-Off shall be applied against your Utilization Payment.

A Performance Set-Off Factor is included in the performance set-off calculations and is described in the *OPA* DR3 Contract.

We calculate Performance Set-Offs to be applied once a month at month-end as a manual line item for the last *trading day* of the month. We use *charge type* 1342 "On behalf of *OPA* for the DR3 Program - Availability Set-Off Payment Settlement Amount" to recover Availability Payments from

participants and *charge type* 1344 "On behalf of *OPA* for the DR3 Program - Utilization Set-Off Payment Settlement Amount" to recover Utilization Payments from participants.[24]

We use *charge type* 1392 "Demand Response 3 Availability Set-Off Payment Balancing Amount" and *charge type* 1394 "Demand Response 3 Utilization Set-Off Payment Balancing Amount" to balance Performance Set-Off amounts.

Additional Availability Set-Offs

In addition to the Performance Set-Offs described above wherein only the highest availability set-off amount shall be applied against your availability payment there are two availability set-offs that will be applied independently of whether or not other set-offs exist.

1. **Planned Non-Performance Availability Set-Off:** The Planned Non-Performance Availability Set-Off is calculated based on the impact to the *electricity system* of a DR3 participant's planned unavailability. The severity of the set-off will depend on whether the participant would have been asked to curtail on the day they chose to be unavailable for *curtailment*.

   We calculate the Planned Non-Performance Availability Set-Offs to be applied once a month at month-end as a manual line item for the last *trading day* of the month. We use *charge type* 1345 "On behalf of *OPA* for the DR3 Program - Planned Non-Performance Event Set-Off Settlement Amt" to recover Availability Payments from participants. We use *charge type* 1395 "Demand Response 3 Planned Non-Performance Event Set-Off Balancing Amount" to balance Planned Non-Performance Set-Off amounts.

2. **Meter Data Set-Off:** The Meter Data Set-Off will be applied against the Availability Payment if a complete set of weekly data for a Settlement Account is not received by the *IESO* by 15:00 EST of the first *business day* of the following week. The amount of the Set-Off for the first occurrence will be 20% of the Availability Payment prorated for the week and will increase in severity thereafter.

   We use *charge type* 1346 "On behalf of *OPA* for the DR3 Program - Meter Data Set-Off Settlement Amount" to recover Availability Payments from participants. Meter Data that is not received by the fourth week after the deadline shall be considered to be a Performance Breach. We use *charge type* 1396 "Demand Response 3 Meter Data Set-Off Balancing Amount" to balance Meter Data Set-Off amounts.

E.3.2 Breach of Contract

Material Non-Performance Events leading to a Performance Breach are described in the DR3 Program Rules in Section 5.4. In the event of a Performance Breach, the Availability Payment for the Contract Month following the month in which the Performance Breach occurs shall be withheld.

For further details with respect to breaches in performance, refer to your *OPA* DR3 Contract.

E.4 OPA's Demand Response (DR2) Program[25]

The *IESO* implemented a contractual load shifting program for participants who are capable of shifting a load of between 5.0 MW and 125.0 MW from the On-Peak Period to the off-peak period. Participants in DR2 will choose to load shift for a four to twelve hour period.

[24] Ibid

[25] In this section, "you" refers to a DR2 participant.

This section sets out how the *IESO* settles the DR2 Program. To the extent of any inconsistency between the provisions of the DR2 Program rules and this section, the DR2 Program rules shall govern.

The On-Peak Period refers to the hours between 7:00 am and 7:00 pm EPT [26] during business days only. You may select a time period of four to twelve consecutive hours for your "On-Peak Contract Period". Refer to the *OPA*'s DR2 Program Rules for full details.

As a DR2 participant, you are paid a monthly Availability Payment for being available for load shifting. In addition to the Availability Payment, you are also entitled to Utilization Payments when your *energy* savings from load shifting are less than the guaranteed *energy* savings threshold set by the *OPA*. The *OPA* will publish, from time to time, the minimum weekly *HOEP* differential rates between each hour on-peak and the average off-peak price.

As a DR2 participant, you are obliged under your contract with the *OPA*, to load shift according to your DR2 Schedule(s). Each DR2 Schedule specifies the quantity of MW that you have contracted to load shift, your on-peak contract period, the term of the schedule (one, three or five years), and the relevant *settlement* account to be used for the purposes of *settlement*. The *settlements* of DR2 Schedules are based on the total contracted MW for all DR2 Schedules at the same *settlement* account and the applicable compensation rates.

Settlement payments are subject to Performance Set-Offs for both Availability and Utilization for failure to comply with DR2 Contract terms including:

- maintaining a Required Reliability Ratio of at least 90% during the shoulder seasons and at least 95% during the summer and winter seasons;
- failing to confirm, or confirming late, as required by us; or
- confirming less than 90% during the shoulder seasons and 95% during the summer and winter seasons of the contacted MW for an hour.

Additionally, DR2 participants will be subject to an Availability Payment Set-Off for:

- any days that they declare a planned non-performance event; or
- failing to deliver *meter* data in a timely manner.

Note: *Generation* is not permitted as a means of contributing towards load shifting under DR2.

E.4.1 Settlement of Demand Response Payments

How Availability Payments Are Settled

Each month, you will receive an Availability Payment for each Settlement Account based on your Contracted MWs and the Availability Rate as described in the DR2 Program Rules. Should a participant have multiple DR2 Schedules for the same Settlement Account, the Availability Rate applicable is the weighted average of the availability rates for all of the DR2 Schedules and similarly, the Contracted MWs are the sum total of all your contract schedules.

We calculate Availability Payments once a month in the month following the contract month and apply them as a manual line item to the last *trading day* of the month following the contract month.

[26] EPT means Eastern Prevailing Time, being either Eastern Standard Time or Eastern Daylight Savings Time, as in effect from time to time.

We use *charge type* 1330 "On behalf of *OPA* for the DR2 Program - Availability Payment Settlement Amount" for Availability Payments to participants.[27]

Where you have multiple DR2 Schedules at a given Settlement Account, these DR2 Schedules are aggregated into one manual line item for *settlement* purposes.

We recover availability payments through *charge type* 1380 "Demand Response 2 Availability Payment Balancing Amount".

How Utilization Payments Are Settled

In addition to your monthly availability payment, you are entitled to receive a Utilization Payment if your weekly *energy* savings are less than the guaranteed minimum amount published by the *OPA*. The payment is based on your actual load reduction during each On-Peak contract period, and the difference between the Minimum Weekly HOEP Differential Rate and the Actual Weekly HOEP Differential.

Utilization Payments are limited to the lesser of the confirmed MWhs or actual load reduction up to the total contracted MWhs.

We calculate Utilization Payments once a month in the month following the contract month and apply them as a manual item to the last *trading day* of the month following the contract month. We use *charge type* 1332 "On behalf of *OPA* for the DR2 Program - Utilization Payment Settlement Amount" for Utilization Payments to participants.[28]

We recover utilization payment through *charge type* 1382 "Demand Response 2 Utilization Payment Balancing Amount".

How We Process Your Meter Data

As part of the DR2 application, participants must submit a Measurement & Verification Plan (M&V Plan) for each Settlement Account. Load shifting is determined by comparing your actual on-peak consumption to your baseline consumption. The calculation of your baseline is described in the *OPA* DR2 Program Rules.

All load shifting must be metered using wholesale or retail revenue meters that meet Measurement Canada standards. For DR2 participants that are not *IESO administered market participants*, we will use:

- your retail revenue hourly *meter* data submitted by 15:00 EST on the first *business day* of the following week; and
- revisions to the metering data received by 15:00 EST on the last *business day* of the contract month following the event.

For DR2 *participants* that are *market participants*, we will use your revenue metering data that we've collected as part of our market *settlement* process.

We verify the actual *metering data* against the M&V Plan and our calculations.

Calculating Performance Set-Offs

Shifting load from the On-Peak Contract Period to the Off-Peak Period is a contractual obligation and subject to performance criteria. Performance criteria consist of:

[27] Refer to "IESO Charge Types and Equations" and "File Format Specification for Settlement Statement Files and Data Files" located on the Technical Interfaces page of the IESO Web site for details of these *charge types*.

[28] Ibid

1. **Reliability**: You are required to provide a minimum level of reliability with respect to load shifting of 95% during the summer and winter seasons and 90% during the Shoulder Seasons. This applies to each Settlement Account for both an Actual MW Reliability Ratio for each On-Peak Contract hour and an Actual MWh Reliability Ratio for each On-Peak Contract Period. Any reliability ratios less than the seasonal rates of 95% and 90% are subject to both availability and utilization payment set-offs.
2. **Timely Confirmation**: Confirmation of the contracted MW for each On-Peak contract hour is only required if there is a change in the quantity of MW and/or the duration of the contract period. If a Confirmation is required by us and you fail to notify us or if you notify us after the Confirmation deadline, you are subject to availability and utilization payment set-offs. The severity of the set-off will depend on how late the Confirmation is received.
3. **Low Confirmation**: If your Confirmed MWs are less than 95% of the contracted MW during the summer and winter seasons and 90% of the contracted MW during the shoulder seasons for one or more On-Peak Contract Hours, a Performance Set-Off will be calculated for each applicable On-Peak Contract Hour. This Set-Off will apply even if the actual quantity of MW is equal to or greater than the Contracted MW.
4. **Non-Performance:** A Performance Set-Off will be calculated based on the operating state of the *electricity system* when a DR2 participant takes a Planned Non-Performance event. Unlike items 1 through 3 above, however, Planned Non-Performance set-offs apply only to the availability payment.

If more than one of the set-offs listed above apply to a *settlement* account, only the highest availability set-off amount shall be applied against your availability payment (one of items 1 – 4) and similarly, only the highest utilization set-off (one of items 1 – 3) shall be applied against your utilization payment.

We calculate Performance Set-Offs to be applied once a month at month-end as a manual line item for the last *trading day* of the month. We use *charge type* 1331 "On behalf of *OPA* for the DR2 Program - Availability Set-Off Settlement Amount" to recover Availability Payments from participants and *charge type* 1333 "On behalf of *OPA* for the DR2 Program - Utilization Set-Off Settlement Amount" to recover Utilization Payments from participants.[29]

We use *charge type* 1381 "Demand Response 2 Availability Set-Off Balancing Amount" and *charge type* 1383 "Demand Response 2 Utilization Set-Off Balancing Amount" to balance Performance Set-Off amounts.

Processing Meter Data Set-Offs

In addition to the Performance Set Offs, a Meter Data Set-Off will be applied against the Availability payment for a Settlement Account if you fail to submit the weekly *meter* data for a Settlement Account to us by 15:00 EST on the first *business day* of the following week. The amount of the Set-Off for the first occurrence will be 20% of the Availability Payment pro-rated for the week and will increase in severity thereafter.

We use *charge* type 1334 "On behalf of *OPA* for the DR2 Program - Meter Data Set-Off Settlement Amount" to recover Availability Payments from participants. Meter data not received by the fourth week after the deadline shall be considered a Performance Breach. We use *charge type* 1384 "Demand Response 2 Meter Data Set-Off Balancing Amount" to balance Meter Data Set-Off amounts.

[29] Ibid

E.4.2 Total Monthly Payment

The total amount payable each month, (i.e., the sum of all Availability payments and Utilization payments less any Set-Offs) to each DR2 participant is adjusted by multiplying the monthly total by the Implied Load Shift Ratio. Details for determining the Implied Load Shift Ratio, including the Load Shift Credit, are in Section 7.5 of the DR2 Program Rules.

E.4.3 Breach of Contract

Material Non-Performance Events leading to a Performance Breach are described in the DR2 Program Rules in Section 6.7. In the event of a Performance Breach, the Availability Payment for all of the DR2 Schedules at that Settlement Account for the Contract Month following the month in which the Performance Breach occurs shall be withheld.

For further details with respect to breaches in performance, refer to the *OPA* DR2 Program Rules.

E.5 Limiting Constrained Off CMSC Payments to Importers Injecting into Designated Chronically Congested Areas

If you are a *market participant* that has offered to inject *energy* over an *intertie*, you may have been *constrained off* by the *IESO* and may be eligible for *constrained off* congestion management *settlement* credit (CMSC) payments from the marketplace.

Certain areas within Ontario have a persistent excess of internal supply, and it is unlikely that any imports offered into these areas will flow. These areas are identified as "Designated Chronically Congested Areas". *Constrained off* CMSC payments under these circumstances will be clawed back if the *constrained off* event appears in the *pre-dispatch schedule* used to determine the *interchange schedule*. The definition for *designated chronically congested area* is as follows:

Designated Chronically Congested Area

A *designated chronically congested area* is an area of oversupply due to transmission constraints, for which persistent excess of internal supply results in little chance for imports to flow, causing *constrained off* CMSC payments. A *designated chronically congested area* is currently defined as an area designated as a *constrained off* watch zone (for injections). Refer to Market Manual 2.12 for more information on the COWZ designation process.

Effective October 1, 2012 with the implementation of *market rule* amendment MR-00395-R00, the Northwest, including the Manitoba and Minnesota *interties*, is identified as a *designated chronically congested area* through its designation as a *constrained off watch zone*.

If the definition of *designated chronically congested area* needs to be revised or an additional area of oversupply needs to be added, the appropriate analysis will be presented to the Inter-Jurisdictional Trading Standing Committee for stakeholder review. *Market manual* revisions will then be posted for stakeholder comment on the Change Notification Listing page of the *IESO* website, following which the *IESO* will respond to each submission and post modified language based on the submissions.

The CMSC recovery is applied as a manual entry to *charge type* 105 "Congestion Management Settlement Credit for Energy" on your *preliminary settlement statement* and *final settlement statement* for the last *trading day* of the month. The adjustment is rebated back to *market participants* as a single manual entry to *charge type* 155 "Congestion Management Settlement Uplift" on the *preliminary settlement statement* and *final settlement statement* for the last *trading day* of the month.

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E.6 OPA Administrative Charge

The "OPA Administration Charge", charge type 754, is a fee levied against all load in Ontario based on AQEW. Every market participant who has AQEW attributed to it during the preceding month pays the OPA Administration Charge based on its AQEW and the OPA fee. The OEB sets the OPA fee annually. Charge type 754 appears on your preliminary and final settlement statements for the last trading day of the month.

The corresponding setoff, *charge type* 704 "OPA Administration Credit", is payable to the IESO on its *preliminary settlement statement* and *final settlement statement* for the last *trading day* of the month.

E.7 Real-time Generation Cost Guarantees

The Real-Time Generation Cost Guarantee (RT-GCG) program, commonly referred to as Spare Generation On-line (SGOL), guarantees start-up costs and *minimum run-time* costs to *market participants* who otherwise might not start up their *generation units* in times when they are not certain they will be dispatched sufficiently to recover those costs. RT-GCG is authorized and governed under the *market rule*s – refer to sections 2.2, 5.7, and 6.3 of Chapter 7; and section 4.7B of Chapter 9.

In order to qualify for an RT-GCG payment you must pass certain eligibility criteria related to how you:

1. offer your *generation unit* for *dispatch*; and

2. operate your *generation unit* in *real time*.

The *settlement* of an RT-GCG event involves the comparison of certain eligible costs to some market revenues your *generation unit* has received for operating at the *minimum generation block run-time* specified for your *generation unit.* If the market revenue is not sufficient to cover the eligible costs, you are compensated for the amount of the shortfall by way of a RT-GCG payment. The details of eligibility and *settlement* are outlined in the following paragraphs.

The Day-Ahead commitment process and related *settlement* payment includes a Production Cost Guarantee (DA-PCG) payable to eligible *generators* that satisfy their Schedules of Record. The DA-PCG which is described in *Market Manual* 9 replaced the previous Day-Ahead Generation Cost Guarantee.

Sections 1.6.4.1 to 1.6.4.3 below describe the RT-GCG submission, eligibility and *settlement*. Section 1.6.4.4 outlines scenarios where the new PCG can interact with a RT-GCG including how *settlement* and eligibility for the RT-GCG are affected.

E.7.1 RT-GCG Submission

Your participation in the RT-GCG program is voluntary. To participate, you must provide additional registration data for your *generation facilities*. You can find the registration eligibility requirements in Chapter 7 Sections 2.2, 5.7 and 6.3A of the *market rules* and in "Market Manual 9: Day-Ahead Commitment Process".

Specifically, the required registration data you must submit for each of your *generation units* to participate in the RT-GCG program is:

- the *minimum loading point;*
- the *minimum generation block run-time;* and

- the *minimum run-time.*

The RT-GCG program allows you to recover certain costs called *combined guaranteed costs* associated with start-up, and operation to the end of the *minimum generation block run-time*, provided that you have not recovered these costs through other market revenues.

To be considered for compensation under RT-GCG, you must provide all of the required information through the "generation cost guarantee" on line data entry screen available on the *IESO* Gateway. You must submit the following information for an RT-GCG event:

- the trade date;
- the event type (select RT for RT-GCG);
- the *generation unit* name;
- the intended synchronization hour ending (EST) at the time you requested qualification of a RT-GCG start;
- the number of actual ramp intervals required to achieve *minimum loading point* after synchronization. The number of ramp intervals represents the number of five minute intervals used to reach *minimum loading point* from synchronization. For example, if your actual ramp time is 3.25 hours, you would submit 39 intervals.
- the fuel costs for start-up and for ramping to *minimum loading point*; and
- the incremental operation and maintenance (O&M) costs associated with start-up and ramping to *minimum loading point*.

Incremental O&M is a cost associated with breaker close and unit operation. These costs are avoidable if the unit does not start. Incremental O&M excludes costs that are independent of unit operation such as lighting, security, and so on. Incremental O&M costs can be broken down according to the reason they are incurred:

1. For startup and ramp: If the cost is incurred because the unit has started and ramps to *minimum loading point*, this lump sum amount can be submitted.
2. For continuing ongoing production: If there is an additional cost for each hour run or per MWh up to *minimum loading point*, related to injections during *minimum generation block run-time*, this cost should be included in your *minimum generation block run-time offer*.

This submission is due by 17:00 on the sixteenth *business day* following the day of synchronization. The *market rules* allow us to audit any information you submit related to an RT-GCG claim if you receive an RT-GCG payment.

In the event it becomes clear the committed unit will not be able to synchronize, ramp to MLP and remain at MLP for the duration of its registered MGBRT, the Replacement Energy Offer Program (REOP) may be used and a different unit, at the same facility and also registered in the RT-GCG program may take its place. If necessary, the mandatory window will be opened so the offers on the replacement unit can be changed to match those of the original. The information submitted through the "generation cost guarantee" on-line data entry screen available on the *IESO* Gateway must relate to the replacement unit, rather than the original. The RT-GCG eligibility criteria will apply to the replacement unit except as noted.

We use the submitted information and the registration information for the *generation unit* when evaluating the RT-GCG eligibility and when we calculate the *settlement*.

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E.7.2 RT-GCG Eligibility

RT-GCG eligibility criteria can be broken down into two distinct phases of the event as follows:

1. Pre-dispatch Scheduling Eligibility Criteria

   We will review the submission and determine if the *generation unit* meets the pre-*dispatch* scheduling requirements as follows:

   - the *generation unit* is not already synchronized at the time of publication of the applicable *pre-dispatch schedule*. If the REOP is used, the replacement unit must also not already be synchronized;
   - you notified the *IESO* control room, of your intent to qualify for an RT-GCG start, and your intent to synchronize in a particular hour ending and run for at least your *minimum generation block run-time*;
   - the *price-quantity pair offer* price corresponding to the *minimum loading point* for all hours of the *minimum generation block run-time* must be the same, until after the *IESO* has constrained the *generation unit*;
   - the *generation unit* must be scheduled in any *pre-dispatch schedule* determined within three hours ahead of the *dispatch hour (i.e.* PD-3, PD-2 or PD-1 published at approximately 12 minutes after the hour) for at least half of *minimum generation block run-time*, rounded up, at *minimum loading point* or high*er*, during the period from the intended synchronization hour ending until the end of the *minimum generation block run-time*, or the end of the *minimum run time,* whichever is earlier; and
   - If the REOP is used, the pre-dispatch schedule eligibility criteria will only apply to the original unit, except as noted above.

2. Real-time Scheduling and Operations Eligibility Criteria

   We will review the submission and determine if the *generation unit m*eets the *real-time* scheduling and operational requirements as follows:

   - the *offer* prices corresponding to the *minimum loading point* for the *minimum generation block run-time* are not increased after notifying the *IESO* of your intention to synchronize or after the *IESO* has applied a manual constraint. If the REOP is used, the offer prices corresponding to the *minimum loading point* for the *minimum generation block run-time* of the replacement unit must not exceed those of the original unit;
   - you synchronize your *generation unit* no later than the end of the *dispatch hour*; and
   - you run your *generation unit* until the end of the *minimum generation block run-time*.

We identify a *generation unit* start-up for *settlement* purposes by using *revenue metering* results for the applicable *trading day*. The metering results must indicate a change from zero in one interval to a sustained positive value for four consecutive intervals. After a valid start-up has been identified, your *generation unit* is determined to be on-line in an interval where your *revenue metering* results show a positive value.

The *minimum generation block run time,* as defined in the *market rules* Chapter 11, is the minimum number of hours your *generation unit* must operate at *minimum loading point.* You are expected to follow *dispatch*, including operating to *minimum loading point*.

If we de-commit a *generation unit* for *reliability* reasons after synchronization, the *generation unit* is still eligible for guarantee payments. You should still submit all the information noted above for the RT-GCG event. The costs submitted should represent the costs incurred prior to de-commitment.

However, you are not eligible for guarantee payments if the *generation unit* fails to run until the end *minimum generation block run-time* for any other reason.

We evaluate the eligibility of an RT-GCG claim when the *settlement* data for the *final settlement statement* are available in the Commercial Reconciliation System.

E.7.3 RT-GCG Settlement

RT-GCG Payments - Costs

The *settlement* of an RT-GCG event involves the comparison of certain eligible costs to some market revenues your *generation unit* has received for operating to the end of the *minimum generation block run-time* specified for your *generation unit*. Chapter 9, Section 4.7B of the *market rules* describes the calculation of the costs, revenues, and the RT-GCG payment.

The total *combined guaranteed costs* will be calculated by the *IESO* and will be the sum of the following costs:

- the submitted fuel costs and incremental O&M costs for start-up and ramp to *minimum loading point*; and
- the *offer* price associated with the real-time *dispatch* multiplied by the *energy* injected, to a maximum of the *minimum loading point,* during the period from the beginning of the *minimum generation block run-time* until the earlier of the end of the *minimum generation block run-time*, or the end of the *minimum run time*.

The *minimum generation block run-time* starts with the first interval after we add the submitted number of actual ramp hours to the valid start-up interval.

RT-GCG Payments - Revenues

Revenues are calculated for the period from start-up until the earlier of the end of the *minimum generation block run-time*, or the *end* of the *minimum run time*. The end of the *minimum generation block run-time* is the first interval after we add the submitted number of actual ramp intervals and the *minimum generation block run-time* to the valid start-up interval.

The revenues included in the calculation are:

- revenue from *energy* sales up to the *minimum loading point*[30] and
- *congestion management settlement credits* (CMSC) associated with Allocated Quantity of Energy Injected (AQEI) up to the *minimum loading point*[31].

When costs exceed the revenues associated with a start, you are paid the difference as an RT-GCG payment.

The RT-GCG *settlement amounts* are calculated at month-end, and applied as a manual line item on the next applicable *preliminary settlement statement* using the *charge type* 133 "Real-time Generation Cost Guarantee Payment". RT-GCG calculations are only included in the current *invoice* for days that have gone final since the last *invoice* was prepared. RT-GCG payments are recovered through an uplift charged to loads and exports through *charge type* 183 "Generation Cost Guarantee Recovery Debit".

[30] We use the value for *minimum loading point* that is in our Market Entry database corresponding to the *start-up time.*

[31] Ibid

E.7.4 Interaction between RT-GCG and PCG

In some cases, the day-ahead schedule may interact with a RT-GCG event. These independent events may link back to one *generation unit* start-up. In these situations, some additional evaluations and calculations will be required for the RT-GCG event. Below are three scenarios and their respective treatment with respect to eligibility and *settlement*.

Scenario 1: RT-GCG Precedes DA Schedule of Record: No Overlap

In this scenario, a *generation unit* starts-up before the first hour of their day-ahead Schedule of Record with sufficient time to complete a RT-GCG run immediately or shortly prior to the first hour of the day-ahead Schedule of Record. In this situation, the end of the RT-GCG event can match exactly with the start of the day-ahead Schedule of Record or the *generation unit* can stay on line for a period between the RT-GCG event and the start of the day-ahead Schedule of Record. In either case both events can be tied back to a single *generation unit* start-up. Figures E-1 and E-2 below depict the two possible situations in this scenario.

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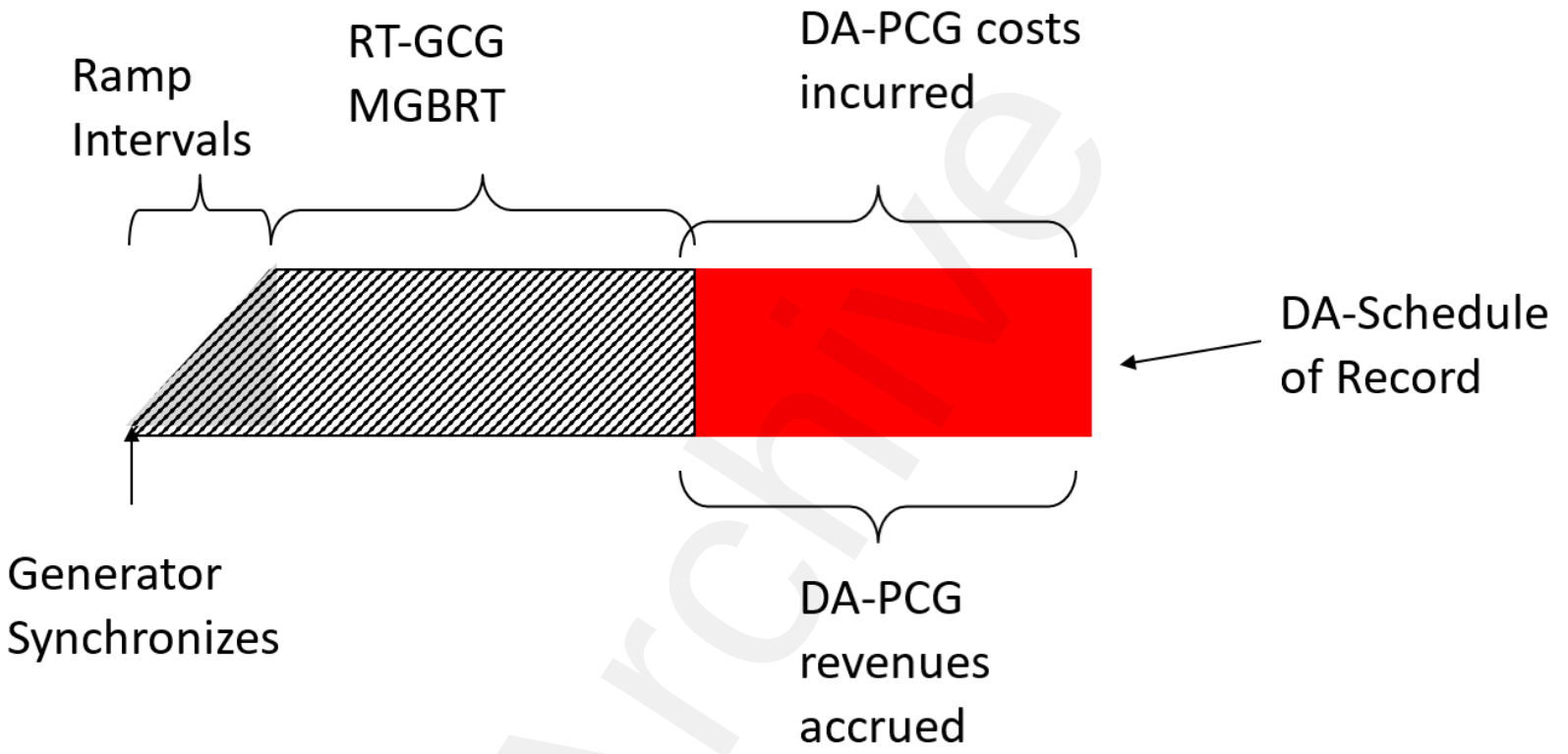
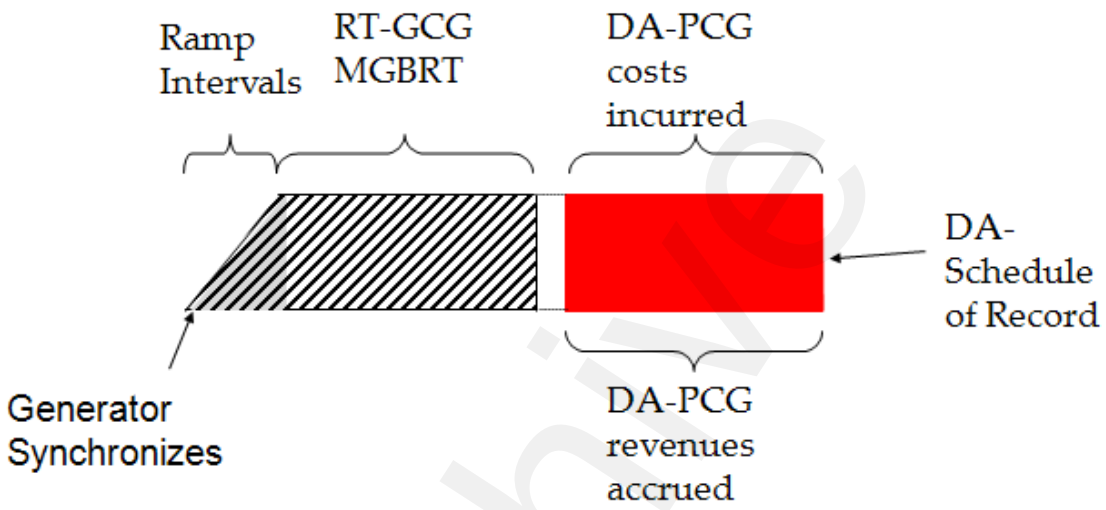


Figure E–1: RT-GCG Precedes DA Schedule of Record: No Overlap - No Gap between Events

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Scenario 2: RT-GCG Precedes DA Schedule of Record**: With Overlap**

In this scenario, a *generation unit* starts-up before the first hour of their day-ahead Schedule of Record, however, the combination of ramp time and *minimum generation block run-time* means the RT-GCG event will overlap with the day-ahead Schedule of Record. In this scenario both events can be tied back to a single *generation unit* start-up. Figure E-2 below depicts this scenario.

Figure E–2: RT-GCG Precedes DA Schedule of Record: No Overlap - Gap between Events

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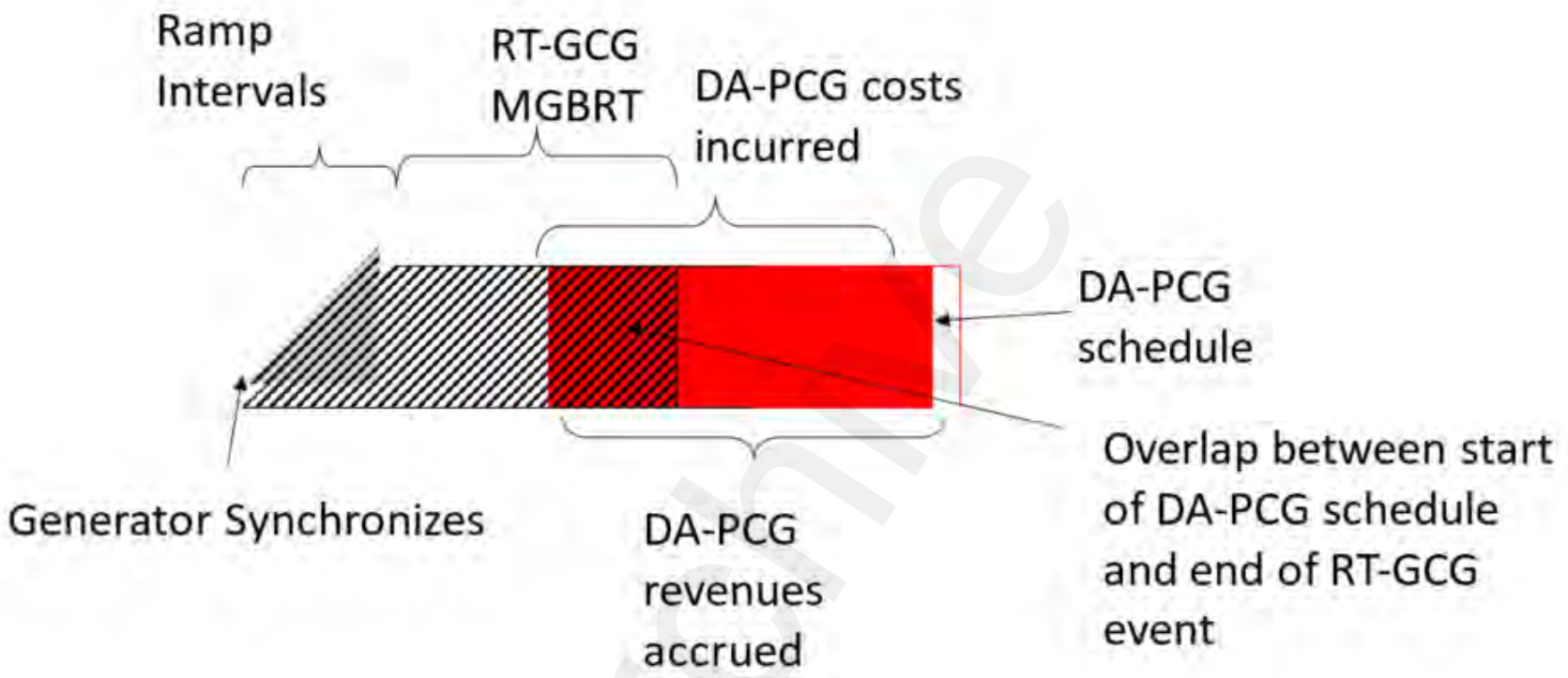


Figure E–3: RT-GCG Precedes DA Schedule of Record: With Overlap

Scenario 3: RT-GCG Interacts with Withdrawn Schedule of Record

This scenario is similar to Scenarios 1 and 2 such that the *generation unit* starts ahead of the Schedule of Record in order to participate in the RT-GCG program, however, in this scenario the *generator* has taken the appropriate actions to withdraw from the day-ahead Schedule of Record and the withdrawal is for reasons within the *generator's* control. This withdrawal may be for all or a portion of the day-ahead Schedule of Record, the result being that the *generator* is not eligible for a DA-PCG *settlement* and further may be subject to a Day Ahead Generator Withdrawal Charge. If the withdrawal of the *generation unit* is for reasons not within the control of the *generator,* then the *generator* continues to be eligible for the DA-PCG *settlement* for the completed hours of the day-ahead schedule, resulting in *settlement* treatment comparable to scenarios 1 or 2 above.

Principles for Eligibility and Settlement:

1) The outcome of the day-ahead process is a Schedule of Record for the next day based on the three part day-ahead bids. These schedules are carried forward into real-time processes with constraints up to *minimum loading point* applied. Similar to manual constraints that are applied in real-time, usually as a result of invoking a RT-GCG start, these PCG constraints will not be considered in RT-GCG Pre-dispatch eligibility.

2) In scenarios 1 and 2 above, where both the DA-PCG event and the RT-GCG event can be tied to the same *generation unit* start-up, and the fuel costs for start-up and ramping to *minimum loading point* along with the related incremental O&M costs are eligible for inclusion in the DA-PCG *settlement*, these costs will not be considered in the assessment of the RT-GCG *settlement*.

   The *generator* will indicate zero for these costs in the RT-GCG submission through the *IESO* in this situation. In the event that the RT-GCG event interacts with a DA-PCG event under scenarios 1 and 2 as described above, and the submitted start-up fuel and O&M costs submitted are not zero, these submitted costs will be deemed as unreasonable and *settlement* of the RT-GCG event will not include these costs, unless strong evidence exists to the contrary.

   If the fuel costs for start-up and ramping to *minimum loading point* along with the related incremental O&M costs are not eligible for inclusion in the DA-PCG *settlement*, these costs will be considered in the assessment of the RT-GCG *settlement* and submitted through the *IESO* Gateway.

3) In scenario 3 above, where the *generation unit* is not eligible for a DA-PCG *settlement*, the fuel costs for start-up and ramping to *minimum loading point* along with the related incremental O&M costs will be included in the assessment of the RT-GCG *settlement*. These costs will be submitted as part of the RT-GCG claim in the *IESO* Gateway.

The table below provides the details for the *submission,* eligibility, and *settlement* of the any RT-GCG claim under the three potential scenarios where there is interaction with a Day-Ahead PCG event.

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		RT-GCG Precedes day-ahead Schedule of Record: *No Overlap* (Scenario 1)	**RT-GCG Precedes day-ahead Schedule of Record: With *Overlap* (Scenario 2)**	**RT-GCG Precedes withdrawn day-ahead Schedule of Record (Scenario 3)**
RT-GCG Submission	• the trade date; • the event type (select RT for RT-GCG); • the *generation unit* name;	No change	No change	No change
	• the intended synchronization hour ending (EST)	No change	No change	No change
	• the number of actual ramp intervals required to achieve *minimum loading point*	No change	No change	No change
	• the fuel costs of start-up and of ramping to *minimum loading point*; • the incremental O&M costs associated with start-up and ramping to *minimum loading point*.	The treatment and submission of fuel costs for start-up and for ramping to *minimum loading point* are outlined in Principle (2) above.	The treatment and submission of fuel costs for start-up and for ramping to *minimum loading point* are outlined in Principle (2) above.	No change
Eligibility	• the *generation unit* is not already synchronized at the time of *publication* of the applicable *pre-dispatch schedule*;	No change	No change	No change
	• you notified the *IESO* control room, of your intent to qualify for an RT-GCG start, and run for at least your *minimum generation block run-time*;	No change	No change	No change
	• the *price-quantity pair offer* price corresponding to the *minimum loading point* for all hours of the *minimum generation block run-time* must be the same	No change	No change	No change

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		RT-GCG Precedes day-ahead Schedule of Record: *No Overlap* (Scenario 1)	**RT-GCG Precedes day-ahead Schedule of Record: With *Overlap* (Scenario 2)**	**RT-GCG Precedes withdrawn day-ahead Schedule of Record (Scenario 3)**
	• the *generation unit* must be scheduled in any *pre-dispatch schedule* determined within three hours ahead of the *dispatch hour (i.e.* PD-3, PD-2 or PD-1) for at least half of *minimum generation block run-time*, at *minimum loading point* hour ending at the end of *the minimum generation block run-time*, or the end of the *minimum run time,* whichever is earlier	*Pre-dispatch Schedules* with either manual or PCG constraints applied will not be considered	*Pre-dispatch Schedules* with either manual or PCG constraints applied will not be considered	*Pre-dispatch Schedules* with either manual or PCG constraints applied will not be considered
	• the *offer* prices corresponding to the *minimum loading point* for the *minimum generation block run-time* are not increased after notifying the *IESO* of your intention to synchronize or after the *IESO* has applied a manual constraint;	No change	No change	No change
	• you synchronize your *generation unit* no later than the end of the *dispatch hour*; and	No change	No change	No change
	• you run your *generation unit* until the end of the *minimum generation block run-time*.	No change	No change	No change
RT-GCG Cost	• the submitted fuel costs and incremental O&M costs for start-up and ramp to *minimum loading point*;	The treatment and submission of fuel costs for start-up and for ramping to *minimum loading point* are outlined	The treatment and submission of fuel costs for start-up and for ramping to *minimum loading point* are outlined	No change

		RT-GCG Precedes day-ahead Schedule of Record: *No Overlap* (Scenario 1)	**RT-GCG Precedes day-ahead Schedule of Record: With *Overlap* (Scenario 2)**	**RT-GCG Precedes withdrawn day-ahead Schedule of Record (Scenario 3)**
		in Principle (2) above.	in Principle (2) above.	
	• the *offer* price associated with the real-time *dispatch* multiplied by the *energy* injected, to a maximum of the *minimum loading point,* during the period from the beginning of the *minimum generation block run-time* until the earlier of the end of the *minimum generation block run-time*, or the end of the *minimum run time*	No change	Cost from start of MGBRT to start of DA-PCG event	No change
RT-GCG Revenues	• Revenues are calculated for the period from start-up until the earlier of the end of the *minimum generation block run-time*, or the *end* of the *minimum run time including:* • *energy* sales up to the *MLP* • CMSC associated with AQEI up to the *MLP*	No change	Revenue from start up to start of DA-PCG event	No change

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E.8 OPG Rebate Requests for Additional Payments or Returns

The OPG Rebate was paid to eligible *market participants* for the period from May 1, 2006 to April 30, 2009, if the average price of *energy* for OPG's non-prescribed assets was above a specified price during the applicable *settlement* period. The final payment of the OPG Rebate appeared under *charge type* 112 "Ontario Power Generation Rebate" on the May 31, 2009 *preliminary settlement statement*.

Distributors were required to pass OPG Rebate amounts through to their non-Regulated Price Plan (RPP) customers. Eligible *market participants* received a pro rata share of the OPG Rebate Amount based on their load (AQEW) for the applicable *settlement* period. Payments for these OPG Rebates were based on *distributor* submissions made through the online form "OPG Rebate Quarterly Distribution" that is no longer available as of May 1, 2009.

If you are a *distributor* who made an error in the information that was submitted to us for the distribution of the OPG Rebate and you now require additional funds to pass through to your customers, you may submit a request to us.

If you are a *distributor* and you have received funds that you are unable to distribute to your customers, or that have been returned to you by your customers, you must return these funds to us. Please notify us of the amounts to be returned via the "OPG Rebate Returned to IESO" online *settlements* data entry screen, available on the *IESO* Gateway.

E.9 Ontario Clean Energy Benefit

The Ontario Clean Energy Benefit (OCEB) was established by the Ministry of Energy to provide financial assistance to Ontarians to help them with the increased costs of upgrading and modernizing the *energy* infrastructure. The OCEB provides *consumers* with eligible accounts with a monthly 10% rebate off the applicable portion of their electricity bills as described in the *Ontario Clean Energy Benefit Act, 2010*, and Ontario Regulation 495/10. The rebate applies for a five-year period from January 1, 2011 to December 31, 2015.

Ontario Regulation 495/10 directs the *IESO* to reimburse *market participant distributors* for the 10% financial assistance that is provided to *consumers* that have eligible accounts with them; with any of their wholly-embedded *distributors*; and with any licensed retailers that use retailer-consolidated billing and that conduct business in their service area or the service area of any of their wholly-embedded *distributors*. This regulation also directs the *IESO* to reimburse unit sub-*meter* providers[32] for the 10% financial assistance provided by them on their fees and charges for unit sub-metering that appear on invoices issued by them to *consumers* that are entitled to receive financial assistance.

Market participant distributors and unit sub-*meter* providers must submit their claims for reimbursement to us monthly no later than the fourth business day after the last *trading day* of the month. The *settlement* amount for *market participant distributors* and unit sub-*meter* providers will be included on the *preliminary settlement statement* and *final settlement statement* for the last *trading day* of the month under *charge type* 9992 "Ontario Clean Energy Benefit (-10%) Program Settlement Amount". The corresponding set-off is *charge type* 1465 "Ontario Clean Energy Benefit (-10%) Program Balancing Amount". *Charge type* 1465 is balanced by the *IESO* through a charge to the

[32] A unit sub-meter provider is a person licensed by the *OEB* to engage in unit sub-metering, being activities in relation to unit sub-meters in multi-unit complexes. Unit sub-meter means a unit meter that is installed by a unit sub-meter provider in a unit of a multi-unit complex where the multi-unit complex is connected to a bulk meter.

Ministry of Energy on their *preliminary settlement statement* and *final settlement statement* for the last *trading day* of the month.

Distributors that are *market participants* must submit OCEB claims to us via the on-line form "Ontario Clean Energy Benefit (-10%) – LDC". In order to obtain reimbursement from the *IESO,* unit sub-*meter* providers must be registered in the wholesale electricity market and submit OCEB claims to us using the on-line form "Ontario Clean Energy Benefit (-10%) – Unit Sub-Meter Provider" that is also accessible on the *IESO* Gateway. A guide to help unit sub-*meter* providers to prepare their OCEB claims is available at. http://ieso.ca/-/media/files/ieso/document-library/training/guide-to-online-data-submission.pdf

E.10 Capacity Based Demand Response Program

The *capacity based demand response* (CBDR) *program* is designed to bridge the period from the Demand Response 3 contract expiration to the delivery date of the first demand response auction. This section describes the Measurement & Verification Plan process and how the IESO settles the CBDR program.

All capitalized terms used in this section are defined in the "Glossary of Terms for Capacity Based Demand Response" document available on the Market Rules & Manuals Library webpage. Rates mentioned in this section can be found in the CBDR Program Operational Information and Rates document available on the *Capacity Based Demand Response Program* webpage for informational purposes only.

E.10.1 Measurement & Verification Plan

Demand response market participants (DRMPs) participating in the CBDR program must submit a Measurement & Verification Plan (or "M&V Plan") for each Demand Response Account (or "DR Account") to the IESO for review and approval. The M&V Plan shall describe the data acquisition procedure and the analytical methodology that will be used by the DRMP to determine the delivery of Demand Response Curtailment (or "DR Curtailment") by the Project. The M&V Plan should be simple, easy to understand and implement, and provide predictability and consistency. The measurement and verification methodology should be accurate and verifiable.

An M&V Plan may be submitted to: CBDR.MV@ieso.ca at any time. To make changes or updates including but not limited to measurement and verification methodology, addition, deletion or substitution of *demand response contributors* (or "contributors") within a pre-existing Contract Schedule.

E.10.1.1 Submission and Approval of the M&V Plan

Upon receipt of amended M&V Plans, the IESO will review and assess the submission within the timeline indicated on the CBDR Processing Timelines document available on the *Capacity Based Demand Response Program* webpage. If the M&V Plan is completed to the satisfaction of the IESO, the IESO will approve it. If the M&V Plan does not meet IESO's requirements, the IESO may request additional information or reject the M&V Plan at IESO's discretion. The IESO will notify DRMPs of the results of the M&V Plan reviews.

No proposed amendment or modification to an existing M&V Plan including any addition, deletion or substitution of any contributor to any such Project during its respective Schedule Term is effective without written acceptance of the IESO.

The IESO shall have the right to verify and audit all technical, financial, and operational data and systems for the Project and for any contributor. The IESO shall have the right to visit

contributor and/or DRMP site(s) to ensure that there is no Project Amendment that has not been consented to as required in this section. *Demand response aggregators* (or "aggregators") must maintain records of measurement data for all contributors and Activation Notices sent to their contributors specifying the start time, stop times and dates of DR Activations as well as a record of contributors demonstrating the eligible portion of the Monthly Contracted MW that the contributor is providing to the aggregator.

E.10.1.2 M&V Plan Information

The content of M&V Plan submission must meet the following requirements:

a) Each M&V Plan submission shall be complete.

b) Each DRMP must supply sufficient information in order for the IESO, in its sole discretion, to review the M&V Plan, including the following:

i. the names, telephone numbers, and e-mail addresses of the DRMP's contact person(s) with respect to the M&V Plan;

ii. a description of the Project;

iii. reference to a pre-existing Contract Schedule and DR Account;

iv. a description of how the DR Curtailment will reduce demand on the IESO-controlled grid, directly or indirectly;

v. a description of the physical location, names and description of the contributor(s) included;

vi. a single line diagram (SLD) if specifically requested by the IESO and whenever, in the discretion of the IESO, the Load can be transferred to another source that is not set out in the M&V Plan;

vii. where the capacity of a Behind the Meter Generator exceeds the annual peak demand of the Load in which the Behind the Meter Generator is embedded, a declaration that the appropriate technology is in place to prevent electricity generated from being injected into the IESO controlled grid or Local Distribution System;

viii. for *demand response direct participants* (or "direct participants"), two years of historical data to support any request for an Extended Period Planned Non-Performance Event and to support the capacity of each contributor to the Project to provide its portion of the Monthly Contracted MW;

ix. for aggregators, one year of historical data aggregated into one stream of data for all contributors and one year of historical data from each contributor to support the capacity of each contributor to the Project to provide its portion of the Monthly Contracted MW; and

x. with respect to each contributor (whether to an aggregator or a direct participant):

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A. meter type, model and firmware version, Measurement Canada approval reference;
B. meter reference number (badge);
C. IESO reference number (where appropriate);
D. brief description of the Interruptible Load or Behind the Meter Generator measured;
E. feeder number (where appropriate);
F. meter seal expiry date(s);
G. confirmation of ability to deliver Interval measurement data;
H. instrument transformer information, including model numbers, Measurement Canada approval references, ratios, accuracy; and
I. Verification Report which compares the independent source measurement data (hourly) and contributor measurement data (hourly).

The DRMP shall acknowledge within the M&V Plan, for each contributor where some portion of the required information is not readily available and reasonable efforts have been undertaken to secure such information, that such information shall be subject to acceptance or rejection at the sole and absolute discretion of the IESO.

c) The IESO will create a settlement map which represents the DR Account. The IESO will:

i. map all kWh delivered and received meter point data streams to the DR Account; and

ii. issue site registration reports (SRR) to the DRMP for signature and confirmation of their acceptance of the settlement map.

Not all combinations of measurement data submission will be allowed by the IESO. Direct participants who participate in the Ontario wholesale electricity markets will be considered by the IESO to have Class 1 measurement data, aggregators will be considered by the IESO to have Class 2 measurement data and direct participants who participate in the Ontario retail electricity markets will be considered by the IESO to have Class 3 measurement data. The allowable forms and combinations of measurement data submission with respect to a DR Account will be as follows:

- only one of Class 1^n, Class 2^n, or Class 3^n measurement data; or
- Class 1^n and Class 3^n which may be aggregated measurement data, where 1^n means Class 1 measurement data from 1 to n sources and 3^n means Class 3 measurement data from 1 to n sources.

d) The following additional principles shall apply to the development and evaluation of the M&V Plan:

i. measurement error correction of the data is not permitted for Class 2 and Class 3 measurement data;

ii. loss adjustment of measurement data is not permitted; and

iii. all Load reductions must be metered using a revenue meter that complies with Measurement Canada standards; statistical methods, operational meters, SCADA

(supervisory control and data acquisition) and other non-meter means are not permitted.

E.10.2 Contributor Management

DRMPs may not increase their Monthly or Daily Contracted MW in any given month above their total aggregated MW zonal cap for each IESO CBDR Resource. Each DRMP will be provided a DR Zonal MW cap at the start of the CBDR program for each IESO CBDR Resource for which they have active DR Accounts and Contract Schedules. The zonal cap will be the maximum amount of MW that a DRMP can subscribe on aggregate within an IESO CBDR Resource.

Contributor changes will fall under two categories: Remove or Add. DRMPs must state the existing DR Account and Contract Schedule that any contributor is being removed from or added to when submitting their changes. Changes must be communicated to CBDR.MV@ieso.ca using the CBDR Contributor Form (available on the Market Rules and Manuals page). No new DR Accounts or Contract Schedules will be created under CBDR. Contributor management must follow the CBDR Processing Timelines document available on the *Capacity Based Demand Response Program* webpage. Contributor changes will occur in the order requested by the DRMP in the contributor change email and the following rules will apply under each scenario.

E.10.2.1 Removing a Contributor

Removing a contributor will reduce the Monthly Contracted MW under a DRMP's IESO CBDR Resource for some or all months and so, will be accepted under all conditions. The contributor will be removed from the Contract Schedule and will reduce the aggregate MW subscription for the CBDR Resource – leaving space for DRMPs to add contributors. Removing a Contributor will not reduce the participant's zonal cap; it will reduce subscription and will create space for capacity to be added.

E.10.2.2 Adding a Contributor

Adding a contributor will only be accepted if the addition does not put a DRMPs aggregate zonal DR capacity subscription over its set DR Zonal MW Cap. Since participants may oversubscribe contributors in a Contract Schedule, the IESO will add the contributor to a Contract Schedule but will only allow the affected Contract Schedule's Monthly Contracted MW to increase to the CBDR Resource's maximum capacity and any remaining contracted capacity of the contributor will be deemed as oversubscription.

Upon transitioning into the CBDR program, CBDR Contract Schedules were established using terms that reflected the quantities, expiry dates and Availability Rates of DR3 Contract Schedules that had existed under the DR3 Program. In addition, each CBDR Contract Schedule has a monthly DR capacity quantity, referred to as the Contractual MW, established to provide a reference threshold for the addition and removal of contributors to aid DRMPs in managing contributors across their Contract Schedules.

For greater clarity, contributor changes that impact CBDR Contract Schedules are subject to the following rules:

1. A Contract Schedule's Monthly Contracted MW can be increased to accommodate the addition of a contributor up to its Contractual MW quantity.

2. A Contract Schedule's Monthly Contracted MW may be increased beyond its Contractual MW quantity if:

i. The increase does not exceed the difference between the DR Zonal MW Cap and the sum of Monthly Contracted MW of all Contract Schedules in that CBDR Resource for that month; and
ii. All Contract Schedules in that CBDR Resource for the DRMP have been subscribed to a Monthly Contracted MW equal to or greater than its Contractual MW.

Should the amount of DR capacity provided by contributors to a Contract Schedule fall below its Contractual MW either through the removal of a contributor or through Contributor Loss, the DRMP must replace that contributor to return the Contract Schedule to at least its Contractual MW. Otherwise, Contract Schedules whose Monthly Contracted MW have been increased above the Contractual MW will be reduced back to the Contractual MW value until such time as condition 2 (ii) above is satisfied.

E.10.2.3 Contributor Loss

DRMPs must notify the IESO as soon as possible by emailing: cbdr@ieso.ca to advise the IESO that they have suffered a Contributor Loss. The email should identify both the contributor and the capacity that was lost as well as identify which DR Account and Contract Schedule the contributor belonged to. The IESO will update the DRMPs Monthly Contracted MW to reflect the capacity that has been lost. A DRMP should consider a Contributor Loss to be any sudden loss of capacity that needs to be communicated to the IESO in order to keep an accurate record of actual available capacity.

The Contributor Loss notice allows DRMPs to communicate lost contributors more urgently than the CBDR timelines for removing a contributor allow. In addition to filing the Contributor Loss, the DRMP will have to remove that contributor via a M&V Plan update at the next available opportunity according to the CBDR Processing Timeline. Removal of a contributor is described above. The reduced MW may be replaced at any time before the expiry of the CBDR schedule term, but those MW must be replaced within the same CBDR Resource or 'zone' that they were removed from in order to respect the modelling of resource capacity within the IESO system.

E.10.3 Demand Response Measurement Data

To allow the IESO to determine the CBDR Baseline, performance set-offs, performance breaches, and settlement, weekly submission of demand response (DR) Class 2 and Class 3 measurement data is required. A week starts on a Saturday and ends on a Friday. M&V Plans will be used to verify measurement data for accuracy and ensure adherence to the Market Rules.

For DRMPs that have registered Class 1 measurement data, we will use the revenue measurement data that is collected as part of our market settlement process. When applicable, such DRMPs are to provide After Deadline Outage Day for each DR Account by 15:00 EST on the first business day of the second week following the week to which the data relates. DRMPs may take one After Deadline Outage Day per week.

For DRMPs that have registered Class 2 or Class 3 measurement data, you will be required to submit to: CBDR.Datafiles@ieso.ca the following:

- Upon request, a data file consisting of an initial set of 35 business days by 15:00 EST on the first business day of the first week of the program month (initial baseline data).
- On a weekly basis, weekly retail revenue measurement data (i.e. weekly data file), and After Deadline Outage Day for each DR Account by 15:00 EST on the first business day

of the second week following the week to which the data relates (V1 measurement data). DRMPs may take one After Deadline Outage Day per week.

- If applicable, revisions to the weekly measurement data files can be submitted by 15:00 EST on the last business day of the month following the month for which the data relates (V2 measurement data). You will need to indicate which Intervals have been edited and why.

The IESO has three (3) business days from the V1 measurement data submission deadline (as per the CBDR Processing Timelines document) to process the submitted data file(s) and will notify the DRMP if and only if there are any data file discrepancies or errors found. Upon such notification, the weekly data files containing the data file discrepancies or errors will be deemed as not having been received by the IESO (i.e. undelivered) and the DRMP will be required to resubmit the weekly data without errors. A measurement data set-off will apply. More details on the measurement data set-off can be found in Section 1.6.24.6.5.

In addition to the above noted measurement data, aggregators must submit a log by DR Account, of each contributor that was requested by the aggregator to Curtail by 15:00 EST on the last Business Day of the month following the activation month only for the days when CBDR was Activated. The log shall contain the following information, the date and time of the request, duration of request, amount (in MW) of such request, and the contributor's name. This log will be assessed by the IESO periodically to validate that the DR Curtailment plans are followed through as defined in the M&V Plan.

E.10.3.1 Measurement Data Specification

This section applies to DRMPs that have Class 2 and Class 3 measurement data.

DR measurement data is a feed of two channels of validated, edited, and estimated (VEE) data for each aggregated Facility (Class 2 measurement data) and direct Facility (Class 3 measurement data) for each DR Account at 5 minute Interval. For CBDR, VEE consists of the following checks performed by the IESO and any problems (i.e. data file discrepancies or errors) will be communicated to DRMP:

- Data does not have gaps (i.e. any 5 minute Interval missing from the data file),
- Data does not have overlaps (i.e. any 5 minute Interval that is a duplicate in the data file), and
- File format as defined below.

Measurement data must be provided in a CSV (comma separated values) compatible with the IESO's meter data collection application[33]. The CSV file shall contain two channels of 5 minute engineering unit values. The unit of measurement is kWh delivered (withdrawn from the grid) for channel 1 and kWh received (injected into the grid) for channel 2. The CSV file shall adhere to the following format corresponding to each column name:

- Date: "YYYY/MM/DD"
- Time: "HH:MM"
- Ch1: Numeric "##.###" in kWh up to three decimal places
- Ch2: Numeric "###.###" in kWh up to three decimal places

[33] Refer to Market Manual 5.2 Metering Data Processing for details on the meter data collection application.

Table E–1: Example of Weekly Data File

Date	Time	Ch1	Ch2
2014/03/28	00:20	749.305	0
2014/03/28	00:25	748.455	0
2014/03/28	00:30	745.455	0

The data file must contain 288 rows of data per day, having a beginning time of 00:05 and an end time of 24:00. The time reference shall be in eastern standard time (EST).

E.10.4 M&V Baseline Methodology

DR Curtailment will be calculated for each hour of Activation as the difference between the Project's calculated CBDR Baseline and the Project's measured consumption (or net production) of electricity, subject to adjustment of an in-day adjustment. A CBDR Baseline will be calculated for each DR Account by aggregating all measurement data for all contributors of that DR Account.

E.10.4.1 Suitable Business Day

A suitable business day is any business day where DR measurement data has been submitted and is available to the IESO, excluding days where:

- an Interruptible Load underwent a Planned Non-Performance Event;
- a DRMP undergo a DR Forced Outage;
- a DRMP claimed an After Deadline Outage Day which was accepted by the IESO;
- the IESO issued an Activation Notice;
- the DRMP has responded to the IESO with a Confirmation Notice for less than the Monthly Contracted MW; or
- the DRMP has responded to the IESO with a Confirmation Notice for less than the Contracted Dispatch Period.

E.10.4.2 Capacity Based Demand Response Baseline

For each hour of a DR Activation event, the CBDR Baseline shall be calculated as follows:

CBDR Baseline = Standard Baseline × In-Day Adjustment Factor

Both the standard baseline and the in-day adjustment calculation for any Confirmed Hour of an Activation shall go back to a maximum of thirty-five (35) business days prior to the day of the Activation to establish twenty (20) suitable business days.

If there are insufficient suitable business days within the previous thirty-five (35) business days to establish a standard baseline, then the IESO may elect to utilize only the available suitable business days within the previous thirty-five (35) business days. For example, if less than twenty (20) suitable

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business days was available then all those suitable business days will be used to calculate the standard baseline.

Standard Baseline: High 15 of 20

The standard baseline for any Confirmed Hour of an Activation is the average of the highest fifteen (15) values for the same hour as those of the Activation, in the last twenty (20) suitable business days prior to the Activation.

In-Day Adjustment Factor

The in-day adjustment factor is equal to A ÷ B, where:

A = Average actual consumption during the adjustment window hours on the actual Activation day.

B = Average actual consumption during the adjustment window hours in the past highest fifteen (15) of twenty (20) suitable business days prior to the Activation.

The adjustment window is the three (3) hour window occurring one (1) hour before an Activation event. The in-day adjustment factor can only be as low as 0.8 and as high as 1.2.

E.10.4.3 Contributor Baseline Considerations

Interruptible Load

The CBDR Baseline for direct participant Interruptible Load will be calculated as set out in 1.6.24.4.2. The CBDR Baseline for aggregator Interruptible Load will be calculated as set out in 1.6.24.4.2

Behind the Meter Generators

The CBDR Baseline for DR Accounts with contributor(s) that are Behind the Meter Generator(s) has the following considerations:

a) where a Project consists entirely of Non-Submetered Generators, the calculation is as set out in 1.6.24.4.2;

b) where a Project consists entirely of Sub-Metered Generators, the calculation is as set out in 1.6.24.4.2 except that the average calculations for the standard baseline and the in-day adjustment will use the 'lowest' fifteen (15) values instead of the 'highest' fifteen (15) values; or

c) where a DR Account consists of multiple installations comprised of a mixture of Interruptible Loads, Non-Submetered Generators, and/or Sub-Metered Generators, the calculation shall use the sum of the meters involved.

E.10.5 Settlement of Availability and Utilization Payments

DRMPs are paid a monthly Availability Payment for being available to reduce Load during the Hours of Availability and a Utilization Payment for actual Load DR Curtailment when directed by the IESO. Also, DRMPs will be entitled to receive an Availability Over-Delivery Payment for each hour that the DRMP is available to either reduce more than the registered demand reduction or reduce Load for a longer period than registered, in response to an Open Standby Notification.

For settlement purposes, all Contract Schedules will be aggregated and payment will be made at the DR Account level. Where rates are different for the applicable Contract Schedules within the DR Account, an amount will be calculated based on the weighted average of each rate as weighted by the Monthly Contracted MWs for each Contract Schedule.

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E.10.5.1 Availability Payment

Each month, DRMP will receive an Availability Payment for each DR Account based on the Hours of Availability, Monthly Contracted MW and a weighted average of all the availability rates or adjusted availability rates (which is adjusted for premium zones and discount zones).

The Availability Payment for a DR Account for a given month is calculated as follows:

$$\textbf{Availability Payment} = \mathrm{HA_H} \times \mathrm{MCMW_h} \times \mathrm{AAR}$$

Where:

- '**HA**' (Hours of Availability) means those hours within which a DRMP shall maintain a Contracted Dispatch Period to be available for potential DR Curtailment of that DRMP's Monthly Contracted MW.
- '**MCMW**' (Monthly Contracted MW) means the MW of demand reduction capacity for a specific program month as identified in one or more Contract Schedule(s).
- '**AAR**' (Adjusted Availability Rate), means an amount equal to the Availability Rate, expressed in /MWh, as increased by the Availability Premium or as decreased by the Availability Discount, as the case may be.
- '**H**' is the total hours a DRMP is available in a month.

We use *charge type* 1300 "Capacity Based Demand Response Program Availability Payment Settlement Amount".

E.10.5.2 Availability Over-Delivery Payment

Over-delivery for an Open Standby Notification will result in an Availability Over-Delivery Payment for each hour that exceeded the Monthly Contracted MW or Contracted Dispatch Period.

In each hour, the Confirmed MWs are limited to the lesser of the Monthly Contracted MW plus 15 MW or 130% of the Monthly Contracted MW.

The Availability Over-Delivery Payment for a DR Account for a given month is calculated as follows:

Availability Over-Delivery Payment = $\sum_H (\mathrm{CMW_h} - \mathrm{MCMW_h}) \times \mathrm{AODR_h}$

Where:

- '**CMW**' (Confirmed MW), means the number of MW available for DR Curtailment by the DRMP.
- '**MCMW**' (Monthly Contracted MW) as defined above.
- '**AODR**' (availability over-delivery rate), means the over delivery rate.
- '**H**' is the set of all hours 'h' in the month where the 'CMW' exceeded the 'MCMW'.

We use *charge type* 1301 "Capacity Based Demand Response Program Availability Over-Delivery Settlement Amt".

E.10.5.3 Utilization Payment

DRMPs will be paid for the amount of Load reduction the DRMP actually provided for a DR Activation for each DR Account based on the Actual Activated MWh and the utilization rate.

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The Actual Activated MWhs are the metered reduction for the Activation Period. The Actual Activated MWh amount can be a positive or negative number.

For Load reduction payments, the total reduction cannot exceed the product of the Activiation MW and the Activation Period, plus the lesser of an additional 15 MW per hour of the Activation Period or 15% of the Activation MW per hour of the Activation Period. Utilization Payments will not be paid during periods of Planned Non-Performance Events even if the IESO issued an Activation Notice.

The Utilization Payment for a DR Account for a given month is calculated as follows:

$$\text{Utilization Payment} = [\sum_{H} (\mathbf{AAM_h \times UR_h})] \quad - \quad [\sum_{H} (\mathbf{NG_h \times MIN(HOEP, UR_h)})]$$

Where:

- '**AAM**' (Actual Activated MWh), means the number of MWh Curtailed by a DRMP when requested by the IESO, as measured through the use of electricity meter(s). DR Curtailment shall not exceed the product of the Activation MW and the Activation Period, plus the lesser of an additional 15% of the Activation MW per hour of the Activation Period or 15 MW per hour of the Activation Period.
- '**UR**' (utilization rate), means the rates, expressed in $/MWh.
- '**NG**' (net generation), means the MWh of net electricity generated by any contributor that is a Behind the Meter Generator.
- '**HOEP**' (*Hourly Ontario Energy Price*) as defined in the Market Rules.
- '**H**' is the total hours 'h' a DRMP is Activated in a month.

We use *charge type* 1303 "Capacity Based Demand Response Program Utilization Payment Settlement Amount"**.**

E.10.6 Settlement of Performance Set-Offs

DRMPs are relied upon by the IESO when assessing adequacy, forecasting demand, and managing system performance. DRMPs are required to maintain a reliability rate of at least 85% for each and every Interval of an Activation Hour for each DR Account, and fulfill other requirements set out below, in order to avoid the imposition of performance set-offs.

The reliability rate with respect to such Interval "*i*" shall be calculated as follows:

$$\boldsymbol{Reliability\ Rate_i = \frac{Actual\ Activated\ MWh\ per\ Interval}{Activation\ MW \times \frac{1}{12}\ of\ an\ hour}} \times \mathbf{100}$$

The resulting reliability rate for an Interval shall not exceed 100%.

Where there is more than one Contract Schedule in a given DR Account, the reliability rate will be calculated on the aggregated Actual Activated MWh and Activation MWs of all the Contract Schedules in that DR Account.

E.10.6.1 Performance Set-Off Factors

The table below sets out the performance set-off factors to be applied to availability set-off and utilization set-off calculations where performance set-off factor is used.

Table E–2: Performance Set-Off Factors

Performance Set-Off Factor	Circumstances in which the Performance Set-Off Factor is to be applied
2.0	• The reliability rate in any one or more Intervals is less than 85%; or • If a Confirmation is required, the IESO has not received such Confirmation three or more hours prior to the commencement of the Activation Period to which the Standby Notification relates. This shall not apply to a Confirmation for more than the Monthly Contracted MW in response to an Open Standby Notification; or • The DRMP has advised the IESO, less than three hours prior to the commencement of the Activation Period to which the Standby Notification relates, that the DRMP if not fully available for Curtailment; or • The IESO has determined that the DRMP was not fully available for Curtailment in relation to the Activation Period to which the Standby Notification relates.
1.50	• If a Confirmation is required, the IESO has received such Confirmation more than 30 minutes late, but more than three hours prior to the commencement of the Activation Period to which the Standby Notification relates, and the Confirmed MW for any one or more Confirmed Hours within the Contracted Dispatch Period is less than 95% of the Monthly Contracted MW. This shall not apply to a Confirmation for more than the Monthly Contracted MW in response to an Open Standby Notification; or • The DRMP has advised the IESO, three or more hours prior to the commencement of the Activation Period to which the Standby Notification relates, that the DRMP is not fully available for Curtailment.
1.25	• If a Confirmation is required, the IESO has received such Confirmation 30 minutes late or less. This shall not apply to a Confirmation for more than the Monthly Contracted MW in response to an Open Standby Notification; or • If a Confirmation is required, the Confirmed MW for any one or more Confirmed Hours within the Contracted Dispatch Period is less than 95% of the Monthly Contracted MW.

E.10.6.2 Availability Set-Off

The availability set-off applied to a DR Account will be the greatest of (i) the availability set-off (reliability), (ii) availability set-off (timely Confirmation), and (iii) availability set-off (low Confirmation) for each DR Activation event (as calculated below). In the event that the availability set-off exceeds the Availability Payment, then the excess is considered owed by the DRMP to the IESO.

Availability Set-Off (Reliability)

Where the reliability rate for a given DR Account is less than 85% during any Interval of an Activation Hour, or where the DR Account is not fully available for Curtailment[34], an availability set-off (reliability) for each such Activation Hour in the Activation Period shall be calculated as follows:

Availability Set-Off (Reliability) = $\sum_H PSO_h \times AAR \times MCMW_h$

Where:

- For each Interval, the reliability rate at a DR Account is defined as the actual reduction divided by the requested reduction; however, the reliability rate cannot exceed 100%.
- '**PSO**' (performance set-off factor) refers to the set of factors defined in section 1.6.24.6.1.
- '**AAR**' (adjusted availability rate) as defined above.
- '**MCMW**' (Monthly Contracted MW) as defined above.
- '**H**' is the set of all Activation Hours 'h' for the Activation Period.

Availability Set-Off (Timely Confirmation)

If the DRMP, regardless of Activation, fails to deliver or delivers late, one or more required Confirmations, then an availability set-off (timely Confirmation) shall be calculated as the sum of the availability set-off (timely Confirmation) for all hours of that Contracted Dispatch Period as follows:

Availability Set-Off (Timely Confirmation) = $PSO \times AAR \times MCMW_h \times CDP$

Where:

- '**CDP**' (Contracted Dispatch Period) means the four consecutive hours. Each Activation Period shall occur within the Hours of Availability, and shall occur within and no more than once in accordance with the Daily Schedule.
- '**PSO**' as defined above.
- '**AAR**' as defined above.
- '**MCMW**' as defined above.

Availability Set-Off (Low Confirmation)

Availability set-off (low Confirmation) applies when the Confirmed MW are less than 95% of the Monthly Contracted MW for a Confirmed Hour of the Contracted Dispatch Period. The calculation is as follows:

Availability Set-Off (Low Confirmation) = $\sum_H (PSO_h \times AAR \times (MCMW_h - CMW))$

Where:

- '**PSO**' as defined above.
- '**AAR**' as defined above.
- '**MCMW**' as defined above.
- '**CMW**' (Confirmed MW) means the number of MW available for DR Curtailment by the DRMP.
- '**H**' is the set of all Confirmed Hours when the Confirmed MWs are less than 95% of the Monthly Contracted MW for the Contracted Dispatch Period.

[34] See Section 1.3.8 of Operations Market Manual 4.2 for details on how not fully available for Curtailment is determined.

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We use *charge type* 1302 "Capacity Based Demand Response Program Availability Set-Off Settlement Amount".

E.10.6.3 Utilization Set-Off

Similar to the availability set-off, the utilization set-off will be the greatest of (i) the utilization set-off (reliability), (ii) utilization set-off (timely Confirmation) and (iii) utilization set-off (low Confirmation) for each DR Activation event (as calculated below). In the event that the utilization set-off exceeds the Utilization Payment, then the excess is considered owed by the DRMP to the IESO.

Utilization Set-Off (Reliability)

The utilization set-off (reliability) applies when the reliability rate for a given DR Account is less than 85% during any Interval of an Activation Hour. The calculation is as follows:

Utilization Set-Off (Reliability) = $\sum_{H} \text{PSO}_{H} \text{ x UR x MCMW}_{H}$

Where:

- For each Interval, the reliability rate at a DR Account is defined as the actual reduction divided by the requested reduction; however, the reliability rate cannot exceed 100%.
- '**PSO**' (performance set-off factor) refers to the set of factors defined in section 1.6.24.6.1.
- '**UR**' (utilization rate) as defined above.
- '**MCMW**' (Monthly Contracted MW) as defined above.
- '**H**' is the set of all Activation Hours 'h' for the Activation Period.

Utilization Set-Off (Timely Confirmation)

If the DRMP, regardless of Activation, fails to deliver or delivers late, a Confirmation that is required by the IESO, a utilization set-off will be calculated for each hour of the Contracted Dispatch Period as follows:

Utilization Set-Off (Timely Confirmation) = $\text{PSO x UR x MCMW}_{h} \text{ x CDP}$

Where:

- '**CDP**' as defined above.
- '**PSO**' as defined above.
- '**UR**' as defined above.
- '**MCMW**' as defined above.

Utilization Set-Off (Low Confirmation)

Utilization set-off (low Confirmation) applies when the Confirmed MW are less than 95% of the Monthly Contracted MW for a Confirmed Hour of the Contracted Dispatch Period. The calculation is as follows:

Utilization Set-Off (Low Confirmation) = $\sum_{H}(\text{PSO x UR x } (\text{MCMW}_{H} - \text{CMW})$

Where:

- '**PSO**' (performance set-off) as defined above.
- '**UR**' (utilization rate) as defined above.
- '**MCMW**' (Monthly Contracted MW) as defined above.
- '**CMW**' (Confirmed MW) as defined above.

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- '**H**' is the set off all Confirmed Hours when the Confirmed MWs are less than 95% of the Monthly Contracted MW for the Contracted Dispatch Period.

We use *charge type* 1304 "Capacity Based Demand Response Program Utilization Set-Off Settlement Amount".

E.10.6.4 Planned Non-Performance Availability Set-Off

The planned non-performance availability set-off is another group of performance set-off. This set-off applies to any business day for which a Planned Non-Performance Event was considered or requested as part of either a single day Planned Non-Performance Event or as part of an Extended Period Planned Non-Performance Event.

There are two different formulas depending on whether the IESO sent any Activation Notices for the DR Account on the day in which such non-performance event was taken. The monthly set-off calculation will be the sum of all planned non-performance availability set-offs **(PNPAS)** as follows:

$PNPAS_m$ = Non-Activation Day Non-Performance Availability Set-Off + Activation Day Non-Performance Availability Set-Off

Non-Activation Day Non-Performance Availability Set-Off

For any Planned Non-Performance Events requested during which the IESO does not send any Activation Notices for a DR Account, then the non-Activation day non-performance availability set-off shall be calculated as follows:

Non-Activation Day Non-Performance Availability Set-Off = ($AAR \times MCMW_h \times HANE_h$)

Where:

- '**AAR**' as defined above.
- '**MCMW**' as defined above.
- '**HANE**' (Hours of Availability for a Planned Non-Performance Event), represents the sum of Hours of Availability for each day in the month for which a Planned Non-Performance Event is requested and for which an Activation Notice is not received by the DRMP.

Activation Day Non-Performance Availability Set-Off

For any Planned Non-Performance Events requested during which the IESO sends an Activation Notice for a DR Account, then the Activation day non-performance availability set-off shall be calculated as follows:

Activation Day Non-Performance Availability Set-Off = ($OH \times AAR \times MCMW_h \times NEWF$)

Where:

- '**OH**' (opportunity hours), means (i) 64 for DR Account with Option A or (ii) 32 for DR Account with Option B.
- '**AAR**' as defined above.
- '**MCMW**' as defined above.
- '**NEWF**' (non-performance event weighting factor), means 100%, unless the Actual Activated MWh per Interval calculated using the standard baseline, as averaged over all of the Intervals in the Contracted Dispatch Period for the Activation, is greater than or equal to the product of the

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Monthly Contracted MW and 1/12 of an hour in which case 'NEWF' means 50%.

We use *charge type* 1305 "Capacity Based Demand Response Program Planned Non-Performance Event Set-Off Amt".

E.10.6.5 DR Measurement Data Set-Off

A DR measurement data set-off will be applied against the Availability Payment for a DR Account if a complete set of weekly measurement data and any DR Forced Outage(s) for that DR Account is not received by the IESO by 15:00 EST on the first business day of the second week following the week for which the data relates.

The DR measurement data set-off is calculated as follows:

DR Measurement Data Set-Off = MDSF x (HA_H x $MCMW_H$ x AAR)

Where:

- '**MDSF**' (measurement data set-off factor), is an increasing factor for every week that the full data remains undelivered. The factor is equal to:
  - 20% for the first week that the full data remains undelivered;
  - 33% for the second week that the full data remains undelivered;
  - 50% for the third week that the full data remains undelivered; and
  - 100% for the fourth week that the full data remains undelivered.
- '**HA**' (Hours of Availability) as defined above.
- '**MRMW**' (Monthly Contracted MW) as defined above.
- '**AAR**' (adjusted availability rate) as defined above.
- '**H**' is the total hours a DRMP is available for the applicable week.

We use *charge type* 1306 "Capacity Based Demand Response Program Measurement Data Set-Off Settlement Amt".

E.10.7 Buy-Downs

Where an event occurs which reduces the Project's ability to Curtail, was not caused by the DRMP, and could not have been reasonably prevented by the DRMP using Commercially Reasonable Efforts, the DRMP shall have one opportunity in the Schedule Term to request for a reduction referred to as buy-down by:

a) Reducing the Monthly Contracted MW to a number of MW that is not less than 5.0 MW, or reducing it entirely to 0 MW; or

b) Designating up to three Daily Schedules per week to be excluded from the days on which the DRMP is required to be available to participate.

To obtain a buy-down, DRMPs will be required to pay the applicable buy-down amount for each Contract Schedule. Each Daily Schedule that is part of a buy-down will be considered as a single day Planned Non-Performance Event and will be subject to the applicable planned non-performance availability set-off. The calculation used is dependent on the type of reduction requested. Calculations for the buy-down amount are defined below. Buy-down rates (R1 and R2) are available on the *Capacity Based Demand Response Program* webpage for informational purposes only.

The buy-down rate used in the buy-down amount is calculated as one of the following based on the Schedule Term of each Contract Schedule:

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Table E–3: Buy-Down Rate Calculation

Schedule Term up to (Year)	Buy-Down Rate is calculated as
1	Buy-Down Rate = R1 x number of months remaining in the Schedule Term
3	Buy-Down Rate = (R2 x number of months remaining in the Schedule Term, up to 24) + (R1 x M, where if the number of months remaining in the Schedule Term exceeds 24, M = months remaining – 24; otherwise M= 0)
5	Buy-Down Rate = (R2 x number of months remaining in the Schedule Term, up to 48) + (R1 x M, where if the number of months remaining in the Schedule Term exceeds 48, M = months remaining – 48; otherwise M = 0)

The buy-down amount (Monthly Contracted MW) is calculated as follows:

Buy-Down Amount (Monthly Contracted MW) = MRMWR x BDR x HAE

Where:

- **'MRMWR'** is the reduction in the Monthly Contracted MW.
- **'BDR'** (buy-down rate).
- **'HAE'** is the number of Hours of Availability that have elapsed in the Schedule Term as of the date that the reduction took effect.

The buy-down amount (Hours of Availability) is calculated as follows:

Buy-Down Amount (Hours of Availability) = MCMW x RD x BDR x HAE

Where:

- **'MCMW'** as defined above.
- **'RD'** (requested day) is the number of business days per week from which the Hours of Availability are to be removed.
- **'BDR'** as defined above.
- **'HAE'** as defined above.

We use *charge type* 1307 "Capacity Based Demand Response Program Buy-Down Settlement Amount".

E.10.8 Performance Breach

Upon successful registration for the CBDR program, the number of performance breaches for a DRMP will be set to zero. Performance breaches are cumulative to, and shall be applied to a DRMP's entire collection of DR Accounts within a CBDR Resource.

A DRMP's compliance with a DR Activation is evaluated at the zonal level using the CBDR Resource as depicted in Appendix H of Market Manual 4.2 when calculating performance breaches. Each DRMP will be assigned to a CBDR Resource and window (early/late) in which they are directly participating in or have contributors.

For both settlement and zonal compliance aggregation purposes, the IESO will assume that the DR Account's Actual Activated MW is zero for all of the Intervals that the data is missing (i.e. undelivered).

A performance breach is defined in relation to a given DRMP as:

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a) the weighted average, over all Confirmed Hours in the Activation period where the Actual Activated MWh divided by the Activation MW for all of the DRMP's DR Accounts within the same CBDR Resource is less than 80%; or,

b) the weighted average, over all Confirmed Hours in the Activation Period, of the Confirmed MW divided by the Monthly Contracted MW for all of the DRMP's DR Accounts within the same CBDR Resource is less than 80%; or

c) the failure of the DRMP to provide to the IESO a complete set of weekly DR measurement data for a DR Account by the fourth week after the deadline.

Performance Breach Events

The IESO will evaluate performance breaches every month and will automatically take the required actions based on the occurrence of the breaches as follows:

First Performance Breach: The Availability Payments for applicable DRMP's DR Accounts within the non-compliant CBDR Resource will be clawed-back for the month in which the performance breach occurred.

Second Performance Breach: The Availability Payments for applicable DRMP's DR Accounts within the non-compliant CBDR Resource will be clawed-back for the month in which the performance breach occurred. The IESO also has the right to terminate some or all of the DR Accounts within a non-compliant CBDR Resource and will determine the need to do this on a case by case basis.

Third Performance Breach: The Availability Payments for applicable DRMP's DR Accounts within the non-compliant CBDR Resource will be clawed-back for the month in which the performance breach occurred. The DRMP may be removed from participation in the CBDR program and/or may be subject to compliance actions in accordance with Section 6 of Chapter 3 of the Market Rules.

For a performance breach event that occurs exclusively as a result of condition c (i.e. failure to provide a complete set of DR measurement data) above, the Availability Payment clawback will only be applied to the DR Account for which the data is missing. However, it will still be counted as a performance breach event for the DRMP and accumulation of performance breaches may lead to termination of DR Accounts and/or termination of the DRMP as described above. For a performance breach event that occurs as a result of either condition a or b above, the Availability Payment clawbacks will apply to all of the DRMP's DR Accounts within the non-compliant CBDR Resource.

We use *charge type* 1308 "Capacity Based Demand Response Program Performance Breach Settlement Amount".

E.10.9 Cost Recovery

In order to keep the cost recovery of CBDR program consistent with the Demand Response 3 program, the IESO will use the following two charge types to recover CBDR costs:

- **1350 "Capacity Based Recovery Amount for Class A Loads"**
- **1351 "Capacity Based Recovery Amount for Class B Loads"**

All CBDR settlement amounts are added together for the month and recovered through these two charges in a manner similar to how we allocate global adjustment costs. Refer to section 1.6.7.8 for details on determination of and allocation of costs for Class A and Class B Loads.

E.10.10 Settlement Statements

E.10.10.1 Preliminary Settlement Statement

A manual line item will be created for each DR Account for each type of payments and set-offs with a non-zero settlement amount for a program month. Manual line items will be added to your preliminary settlement statement for the last trading day of a month following the program month. For example, the CBDR settlement for the program month of July will be included on August 31st preliminary settlement statement.

In addition to monthly settlement, any non-zero adjustment amounts as a result of recalculations due to accepted NOD submissions or as required by the IESO may also appear on your preliminary settlement statement. Preliminary settlement statements will be generated in accordance with the *SSPC* and will be issued via the *IESO* Report Site.

An invoice for amounts owed to or by the DRMP as per the preliminary settlement statement will be made available to the DRMP at the same time on the IESO Report Site.

If you disagree with a settlement amount on your preliminary settlement statement, you may submit a notice of disagreement (NOD) within four (4) business days after the statement has been issued. Refer to Section 1.3.5 'Submitting a Notice of Disagreement' for more information regarding the notice of disagreement process. The resolution process for NODs will then commence between the DRMP and the IESO if the IESO determines the NOD is legitimate.

E.10.10.2 Final Settlement Statement

A final settlement statement will only be issued if there are any adjustments required to amounts on a preliminary settlement statement. Adjustments may be made due to recalculations completed as a result of a NOD submissions or as required by the IESO. Final settlement statements will be generated in accordance with the *SSPC* and will be issued via the *IESO* Report Site.

E.10.10.3 CBDR Program Settlement Report

A CBDR program settlement report is a private report to help DRMPs understand their settlement for that month. This report will be issued to each DRMP on a monthly basis and will contain the supporting information for all DR Accounts. This report will be made available on the same day as the preliminary settlement statement via the *IESO* Report Site.

E.11 Submitting Optional Measurement Data Records

You may submit a request for optional measurement data records to be included in the *settlement* data file. The steps in Figure 2-7 illustrate the process for submitting a request for optional measurement data records to us, and are described in detail in Section 3.7, Table 3-7.

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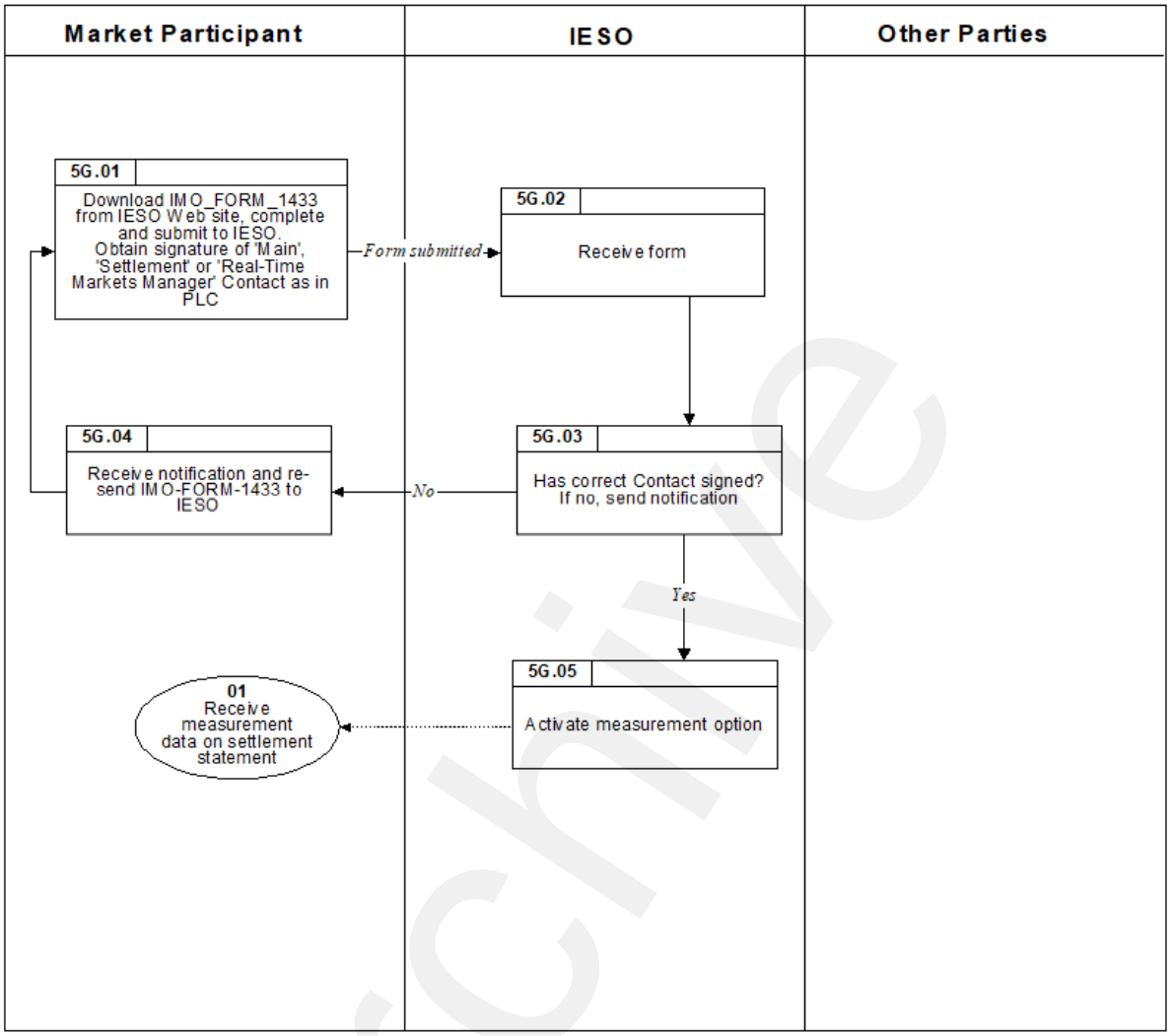


Figure E–4: Work flow for Submitting Optional Measurement Data Records

E.12 Submitting Request for Optional Measurement Data Records

M*arket participants* may request optional measurement data records to be included in the *settlement* data file.

The steps shown in the following table are illustrated in Section 2.7, Figure 2-7.

Archive

Table E–4: Procedural Steps for Submission of Optional Measurement Data Records

Ref.	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
5G.01	Download IMO_FORM_1433 from our web site, complete and submit to us. Obtain signature of 'Main', 'Settlement' or 'Real-Time Markets Manager' Contact as in CDMS.	*Market participant* downloads the form, completes it and submits it to us. The m*arket participant* ensures it is signed by one of 'Main', 'Settlement' or 'Real-Time Markets Manager' contacts.	When *market participant* determines that optional measurement data records are needed.	*Market participant* has requested optional measurement data records.	Fax, mail or courier.	Request for optional measurement data records submitted.
5G.02	Receive form.	We receive completed form for request for optional measurement data records.	After 5G.01.			Form received.
5G.03	Has correct Contact signed? If no, send notification.	We verify that form is complete and verify the signing contact is correct as in CDMS. If not, we inform the *market participant*.	After 5G.02.	Completed request for optional measurement data records.	If required, email.	Completed request for optional measurement data records.
5G.04	Receive notification and re-send IMO_FORM_1433.	*Market participant* receives notification that the incorrect contact has signed the form. The form is corrected and re-sent as in 5G.01.	After 5G.04.	Completed request for optional measurement data records.	Fax, mail or courier.	*Market participant* is aware of incorrect contact and has submitted a correct form.
5G.05	Activate measurement option.	We will include optional measurement data records with *settlement* data files.	After successful 5G.03.	Optional measurement data records included in *settlement* data files.		*Market participant* receives optional measurement data records.

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E.13 Repealed - Fair Hydro Act, 2017

The following provisions of the *Fair Hydro Act, 2017* were repealed effective November 1, 2019. Please refer to sections 1.6.7.7 (Regulated Price Plan) and 1.6.33 (Fair Hydro Act, 2017) for current provisions.

E.13.1.1 Ontario Fair Hydro Plan RPP Consumer Discount

We used *charge type 1142* "Ontario Fair Hydro Plan Eligible RPP Consumer Discount Settlement Amount" for processing *distributor* submissions. The corresponding setoff, *charge type* 1192 "Ontario Fair Hydro Plan Eligible RPP Consumer Discount Balancing Amount" was entered on the IESO's *preliminary settlement statement* and *final settlement statement* for the last *trading day* of the month to balance the market.

E.13.1.2 Global Adjustment Modifier

Under the *Fair Hydro Act, 2017*, certain specified *consumers* who are not regulated rate consumers are entitled to an adjustment to the Global Adjustment (GA) amounts they pay. This adjustment, known as the GA Modifier, is implemented as a dollar-per-megawatt ($/MWh) credit applied to the consumer based on the amount of electricity consumed. The GA Modifier rate is set by the OEB, and is available on IESO's website.

Licensed *distributors* and unit sub-*meter* providers that are *market participants* must submit their claims for reimbursement of the GA Modifier credits paid to their eligible customers. This claim must be submitted monthly to the IESO no later than the fourth *business day* after the last *trading day* of the month. The *settlement amount* for licensed *distributors* and unit sub-*meter* providers will be included on the *preliminary settlement statement* and *final settlement statement* for the last *trading day* of the month under *charge type* 1143 "Ontario Fair Hydro Plan Eligible Non-RPP Consumer Discount Settlement Amount". The corresponding set-off is *charge type* 1193 "Ontario Fair Hydro Plan Eligible Non-RPP Consumer Discount Balancing Amount".

E.13.1.3 Financing Entity

Two additional charge types have been created to settle the administrative costs and interest incurred by the "financing entity" in funding the initiatives under the *Fair Hydro Act, 2017*.

Charge types 1144, "Ontario Fair Hydro Plan Financing Entity Amount" and *charge type* 1145, "Ontario Fair Hydro Plan Financing Entity Interest" have been created for the purpose of settling these amounts. These amounts will be balanced to an IESO variance account under *charge type* 1194, "Ontario Fair Hydro Plan Financing Entity Balancing Amount" and charge *type* 1195, "Ontario Fair Hydro Plan Financing Entity Balancing Interest".

E.13.1.4 Regulatory Asset

As per the *Fair Hydro Act*, 2017, the IESO may, from time-to-time, transfer a specified portion of the "regulatory asset" established through the Act to a financing entity; and an agreement between the IESO and a financing entity in relation to the transfer of a specified portion of the "regulatory asset"

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shall provide for consideration of a payment by the financing entity to the IESO in an amount equal to the amount of the specified portion.

Charge type 6000 "Ontario Fair Hydro Plan - Regulatory Asset Transfer Amount" is the amount debited to the financing entity and *charge type* 6050 "Ontario Fair Hydro Plan - Regulatory Asset Transfer Balancing Amount" is the amount credited to the IESO and is used to reduce the variance account.

E.14 Debt Retirement Charge (DRC)

The *debt retirement charge* (DRC) is charged on the *real-time market settlement statement* to all wholesale *market participants* withdrawing *energy* from the *IESO-controlled grid*. The charge is based on allocated quantity of *energy* withdrawn (AQEW) at each *delivery point*. We must collect and remit payment related to the *debt retirement charge* from you as required by any regulations made under the "*Electricity Act, 1998*".

E.14.1 DRC Exemption

The regulations allow for other collectors and certain other persons to provide *exemption* certificates as described in:

- "Ontario Regulation 493/01 and 494/01"; and
- information guidelines provided by the Ministry of Finance.

If eligible, you can apply to us to be exempt from our collection of the DRC:

- for *energy* you withdraw for your specific *delivery points* to which the *exemption* applies; or
- to all *delivery points* where you withdraw *energy*.

If you wish to be exempt from our collection of the DRC, you should:

- complete the *exemption* certificates as indicated in the regulation; and
- submit the *exemption* certificates by mail or courier to the address provided in the "Contact Us" section on our web site; write on the envelope, "**Attention: *Settlements***"; we will acknowledge receipt of the certificate.

E.14.2 Reduced Debt Reduction Charge (DRC) Certification

The regulation also identifies specific local utility service areas where *facilities* are eligible for reduced DRC rates.

If your *facilities* qualify for the reduced DRC rates:

- download IMO_FORM_1438 "Application for Reduced Debt Retirement Charge Form" from our web site; and
- submit the completed form by mail or courier to the address provided in the "Contact Us" section on our web-site; write on the envelope, "**Attention: Settlements**"; we will acknowledge receipt of the form.

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E.15 Submitting DRC Exemption Certificate

If you are exempt from DRC, you must submit exemption certificates to us. The steps in Figure 2-5 illustrate the process for submitting a DRC exemption certificate to us, and are described in detail in Section 3.5, Table 3-5.

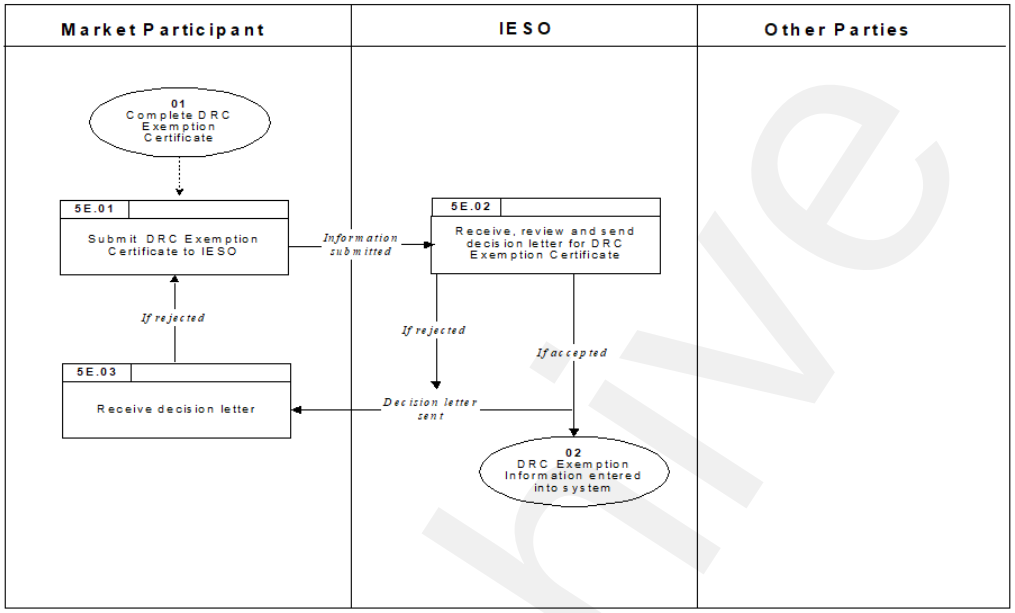


Figure E–5: Work flow for Submitting DRC Exemption Certificate

E.16 Submitting Reduced DRC Certification

You must submit reduced DRC certification form to us. The steps in Figure 2-6 illustrate the process for submitting reduced DRC certification information to us, and are described in detail in Section 3.6, Table 3-6.

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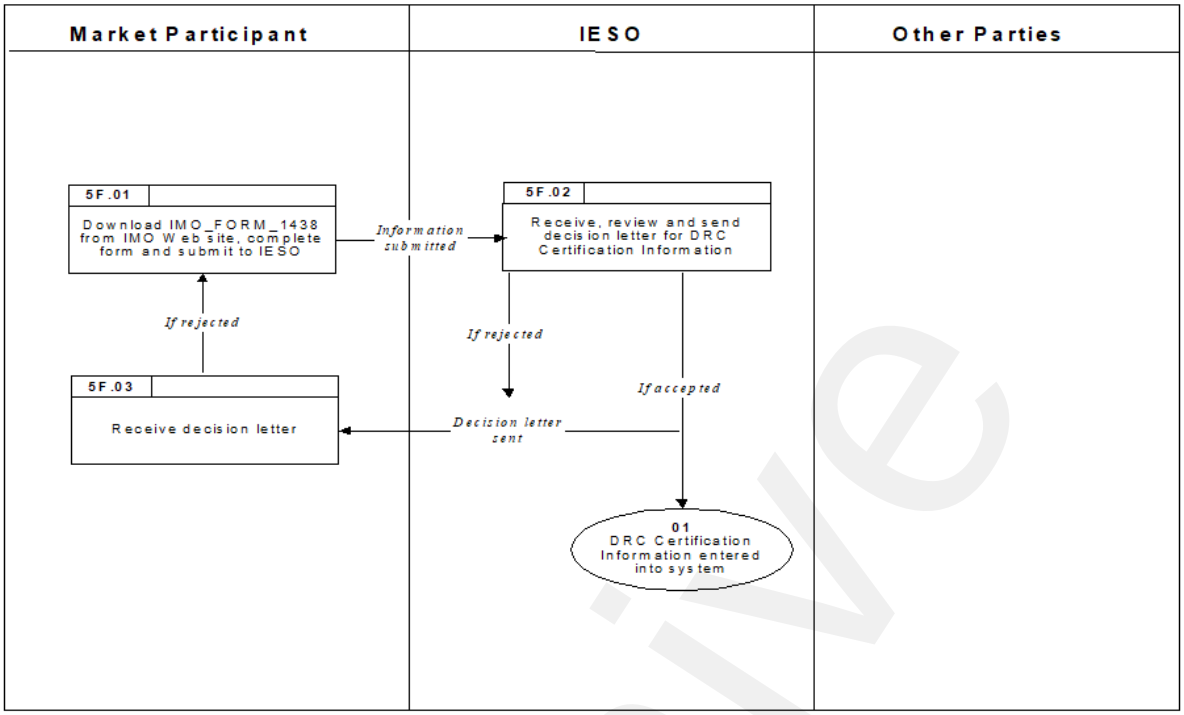


Figure E–6: Work flow for Submitting Reduced DRC Certification Information

E.17 Submitting DRC Exemption Certificate

M*arket participants* must register with the Ministry of Finance as indicated in "Regulation 493/01 and 494/01" and submit DRC exemption information to us in order to be exempt from the *debt retirement charge*.

The steps shown in the following table are illustrated in Section 2.5, Figure 2-5.

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Table E–5: Procedural Steps for Submission of DRC Exemption Certificate

Ref.	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
5E.01	Submit DRC Exemption Certificate to us.	*Market participant* submits hard copy of DRC exemption certificate as indicated in the Ministry of Finance procedure.	When DRC exemption certificate is complete.	Exemption certificate.	Mail or courier.	DRC exemption certificate submitted to us.
5E.02	Receive, review and send decision letter for DRC Exemption Certificate.	We receive DRC exemption certificate, review it for completeness and send a decision letter either accepting the certificate or rejecting it.	Upon receipt.	None.	Fax.	DRC exemption certificate received, reviewed and decision letter sent to *market participant*.
5E.03	Receive decision letter.	*Market participant* receives decision letter from us. If the information was incomplete, the *market participant* revises the information and resubmits it to us.	After Step 5E.02.	None.	Fax.	Decision letter received by *market participant*.

E.18 Submitting Reduced DRC Certification Information

M*arket participants* must complete the reduced DRC certification to be charged the reduced DRC rate as indicated by the Ministry of Finance "Regulation 493/01".

The steps shown in the following table are illustrated in Section 2.6, Figure 2-6.

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Table E–6: Procedural Steps for Submission of Reduced DRC Certification Information

Ref.	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
5F.01	Download IMO_FORM_1438 from our web site, complete form and submit to us.	*Market participant* downloads the Reduced DRC Certification form, completes it and submits it to us.	Prior to *trading day* the DRC reduced rate should apply.	Reduced DRC Certification.	Mail or courier.	Reduced DRC Certification submitted.
5F.02	Receive, review and send decision letter for DRC Certification Information.	We receive the "Reduced Debt Retirement Charge (DRC) Certification" (IMO_FORM_1438), review it for completeness and send a decision letter either accepting or rejecting the information.	Upon receipt.	None.	Fax.	Decision letter sent to *market participant.*
5F.03	Receive decision letter.	*Market participant* receives decision letter. If the information was incomplete, the *market participant* revises the information and resubmits it to us.	After Step 5F.02.	None.	Fax.	Decision letter received by *market participant*.

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– End of Section –

Appendix F: OPG Rebate

F.1 OPG Rebate

Note: The provisions of this Appendix do not apply for any period beginning after April 30, 2009. The provisions of this Appendix have been retained in the event that a re-calculation of the OPG Rebate for any period prior to May 1, 2009 is necessary.

F.1.1 OPG Rebate Calculation

In accordance with our *Independent Electricity System Operator Licence*, we are required to pay the OPG rebate to you if the average price of *energy* for OPG's non-prescribed assets is above a specified price during the applicable Settlement Period. The OPG Rebate is in effect until April 30, 2009.

The OPG Rebate payment is calculated and distributed quarterly to eligible *market participants,* if warranted. Table 1–2 summarizes the Settlement Periods and submission deadlines.

The OPG Rebate amount payable by OPG:

For the Period from May 1, 2006 to April 30, 2009, OPG is to make quarterly payments to the *IESO*, beginning with the OPG Rebate Payment on the October 31, 2006 *settlement statement* as follows:

OPG Rebate amount = Sum over all hours [(HOEP – ORL) x (ONPAO x 0.85 – PAA) + (PAP – PAORL) x PAA)]

Ontario Power Generation's quarterly payments are based on a cumulative calculation commencing May 1, 2006 to the end of each quarter less the same cumulative calculation to the end of the previous quarter. This continues until the final quarter ending April 30, 2009. Where the payment formula results in an amount owing to OPG for any quarter, no such payment will be made to OPG by the *IESO* and any such amount will be carried forward into subsequent quarters.

Where:

ONPA or OPG's Non-Prescribed Assets are those generation assets operated and controlled by Ontario Power Generation in service as of January 1, 2006, excluding Lennox Generating Station, and excluding stations whose generation output is subject to a contract with the *IESO* in the form of a hydroelectric *energy* supply agreement (entered into by the *OPA* and OPG pursuant to a ministerial direction made under section 25.32 of the *Electricity Act, 1998*), that are not prescribed assets under Section 78.1 of the "*Ontario Energy Board Act, 1998*" as amended by the "*Electricity Restructuring Act, 2004*".

HOEP is the *Hourly Ontario Energy Price* as determined by the *IESO*.

ONPAO is the generation output from OPG's Non-Prescribed Assets, over each hour of the quarter adjusted to take account of volumes sold through forward contracts in effect as of January 1, 2005. For greater certainty, any output from ONPA resulting from fuel conversion by Ontario Power Generation in ONPA, or incremental output from ONPA resulting from refurbishment or expansion, or that is subject to a contract with the *OPA* in

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the form of a hydroelectric *energy* supply agreement, [entered into by the *OPA* and OPG pursuant to a ministerial direction made under section 25.32 of the *Electricity Act, 1998*] is to be excluded from ONPAO.

Incremental Output is defined as:

generation output x (new total installed capacity – installed capacity as of January 1, 2006) / new total installed capacity.

ORL is the Ontario Power Generation Revenue limit.

For the period May 1, 2006 to April 30, 2007 ORL is equal to $46/ MWh.

For the period May 1, 2007 to April 30, 2008 ORL is equal to $47/ MWh.

For the period May 1, 2008 to April 30, 2009 ORL is equal to $48/ MWh.

PA is the Pilot Auction administered by the *Ontario Power Authority* in the first half of 2006.

PAA is the volume in MWh over each hour in the quarter that is sold by Ontario Power Generation through the PA.

PAORL is the Pilot Auction Ontario Power Generation Revenue limit.

For the period May 1, 2006 to April 30, 2007 PAORL is equal to $51/ MWh.

For the period May 1, 2007 to April 30, 2008 PAORL is equal to $52/ MWh.

For the period May 1, 2008 to April 30, 2009 PAORL is equal to $53/ MWh.

PAP is the weighted average auction price in $/ MWh over each hour of the quarter realized for the PAA by Ontario Power Generation.

F.1.2 OPG Rebate Payment

If eligible, you will receive a pro rata share of the OPG Rebate Amount based on your allocated quantity of *energy* withdrawn for the applicable *settlement* period. Your OPG Rebate payment appears under *charge type* 112 "Ontario Power Generation Rebate". If the calculated amount of the OPG Rebate is negative, we will not make any rebate payments.

Since the OPG Rebate is already included in the Regulated Price Plan rates established by the *OEB* for *energy*, you will not receive the OPG rebate if:

- You are a *market participant* that is a low-volume or designated *consumer*, as defined in the "*Electricity Act*" and its associated regulations; or
- You are a customer of a *distributor* and a low-volume or designated *consumer*.

Distributors are required to submit information to us in advance of OPG Rebate payments to allow us to determine their OPG Rebate amount. This submission requirement is described below in Section 1.6.3.3.

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F.1.2.1 Distributor Submission Requirement

Market participants that are *distributors* must submit information to us prior to the distribution of the OPG Rebate. We use this information to calculate the OPG Rebate amount for the *distributor*.

For the applicable quarter, *distributors* must advise us of the volume of *energy* withdrawn from the *IESO-controlled grid* that is associated with *consumers* who are not being charged the Regulated Price Plan (RPP) price for their electricity consumption.

The quantity provided must account for the volumes associated with any embedded *distributors* in the *distributor's* service area.

Distributors must submit the Ontario Power Generation Rebate - Quarterly Distributor information to us online. Table F-1 summarizes the submission deadlines for this information. Enter these volumes, rounded to the nearest kWh (3 decimal places on an MWh), via the Settlements community within the *IESO* Gateway.

F.1.2.2 Pass-Through of Rebate

Some *market participants* are required to pass OPG Rebate amounts through to their customers. If you are required to do this, any pass-through amounts that you are unable to distribute or that are returned to you by your customers must be returned to us. Please notify us of the amounts to be returned via the 'OPG Rebate Returned to IESO's *settlements* data entry screen of the *IESO* Gateway.

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Table F–1: Summary of Deadlines

OPG Rebate for:	Deadline for Submission of the OPG Rebate Quarterly Distribution Energy Volume	Applicable Settlement Period (AQEW Totals and Data Required on Form Pertains to):	For Distributors: Include Low Volume and Designated Consumers Known as of:	Rebate Payment to Eligible MPs on Settlement Statement for Trading Day (if warranted):
For the Period from May 1, 2006 to April 30, 2009:				
Quarters ending July 31	3 *business days* before October 31	May 1 – July 31	mid – October	October 31
Quarters ending October 31	3 *business days* before January 31	August 1 – October 31	mid – January	January 31
Quarters ending January 31	3 *business days* before April 30	November 1 – January 31	mid – April	April 30
Quarters ending April 30	3 *business days* before July 31	February 1 – April 30	mid – July	July 31

– End of Section –

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References

Document ID	Document Title
MDP_RUL_0002	Market Rules for the Ontario Electricity Market
PRO-408	Market Manual 1: Connecting to Ontario's Power System, Part 1.5: Market Registration Procedures
MDP_PRO_0017	Market Manual 2: Market Administration, Part 2.1: Dispute Resolution
MDP_MAN_0005	Market Manual 5: Settlements, Part 5.0: Settlements Overview
MDP_PRO_0031	Market Manual 5: Settlements, Part 5.1: Settlement Schedule and Payments Calendars (SSPCs)
MDP_PRO_0032	Market Manual 5 Settlements, Part 5.2: Metering Data Processing
MDP_PRO_0034	Market Manual 5, Settlements, Part 5.3: Submission of Physical Bilateral Contact Data
MDP_PRO_0035	Market Manual 5: Settlements, Part 5.6: Physical Markets Settlement Invoicing
MDP_PRO_0036	Market Manual 5: Settlements, Part 5.9: Settlement Payment Methods and Schedule
MDP_PRO_0046	Market Manual 5: Settlements, Part 5.7: Financial Markets Settlement Statements
MDP_PRO_0047	Market Manual 5: Settlements, Part 5.8: Financial Markets Settlement Invoicing
MDP_PRO_0027	Market Manual 4: Market Operations, Part 4.2: Submission of Dispatch Data in the Real-Time Energy and Operating Reserve Markets
IMP_PRO_0034	Market Manual 4: Market Operations, Part 4.3: Real-Time Scheduling of the Physical Markets
IMP_PRO_0057	Market Manual 3: Metering, Part 3.8 Creating and Maintaining Delivery Point Relationships
IMO_MAN_0024	Market Manual 6: Participant Technical Reference Manual
IESO_MAN_0080	Market Manual 9: Part 9.5. Settlement for Day-Ahead Commitment Process
IMP_GDE_0103	The Applications Status Tool: A User Guide
	Guide to Settlement Claims and Data Submissions via Online IESO
IMP_LST_0001	IESO Charge Types and Equations

Document ID	Document Title
IMP_SPEC_0005	Format Specifications for Settlement Statement Files and Data Files
IMP_SPEC_0006	File Format Specification for Participant Transmission Tariff Data Files
IMP_SPEC_0007	File Format Specification for Transmitter Transmission Tariff Data File
IMP_SPEC_0008	File Format Specification for Transmitter Reconciliation Data File
IMO_SPEC_0100	Outbound Automated Document Application Programming Interface
IMP_REP_0016	Transmission Tariff Peak System Demand Data Report
IMP_AGR_0013	Settlement Agreement between Ontario Power Generation Inc. and the Independent Electricity Market Operator
Quick Take 15	Retrieving Reports via the IESO Reports Site
IESO Step-by-Step Guide	IESO Interactions for Unit Sub-Metering Providers
	OEB Retail Settlement Code
	Ontario Energy Board Act, 1998
	Legislation Bill 4 “An Act to amend the Ontario Energy Board Act 1998 with respect to energy pricing”.
	Legislation Bill 100 "Electricity Restructuring Act, 2004"
	Order-in-Council 141/2006
	Regulation 42/04 (Under the Ontario Energy Board Act, 1998)
	Regulation 43/04 (Under the Ontario Energy Board Act, 1998)
	Regulation 339/02 (Under the Ontario Energy Board Act, 1998) "Electricity Pricing"
	Regulation 341/02 (Under the Ontario Energy Board Act, 1998) "Compensation and Set-Offs Under Part V of the Act"
	Regulation 342/02 (Under the Ontario Energy Board Act, 1998) "Payments to the IMO"
	Regulation 433/02 (Under the Ontario Energy Board Act, 1998) "Electricity Pricing"
	Regulation 435/02 (Under the Ontario Energy Board Act, 1998) "Payments re Section 79.4 of the Act"
	Regulation 436/02 (Under the Ontario Energy Board Act, 1998) "Payments re Various Electricity-Related Charges"

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Document ID	Document Title
	Regulation 427/04 “Payments to the Financial Corp. re Section 78.2 of the Act”
	Regulation 428/04 “Payments re Section 79.4 of the Act”
	Regulation 398/10 enacted in October 2010 Amending Ontario Regulation 429/04 “Adjustments Under Section 25.33 of the Act”
	Regulation 430/04 “Payments re Section 25.33 of the Act”
	Regulation 431/04 “Payments re Section 25.34 of the Act”
	Section 78.3 of the (Ontario Energy Board) Act
	Section 78.4 of the (Ontario Energy Board) Act
	Section 78.5 of the (Ontario Energy Board) Act
	Regulation 53/05 made under “OEB Act, 1998” re “Payments under Section 78.1 of the Act”
	Regulation 95/05 made under “OEB Act, 1998” re “Classes of Consumers and Determination of Rates”
	Regulation 98/05 made under “OEB Act, 1998” re “Payments re Various Electricity-Related Charges”
	Regulation 330/09 made under “OEB Act, 1998” re “Cost recovery regarding section 79.1 of the Act”
	Regulation 66/10 made under “OEB Act, 1998” re “Assessments for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program Costs”.
	Regulation 495/10 made under “Ontario Clean Energy Benefit Act, 2010”.
	Regulation 363/16 made under “Ontario Rebate for Electricity Consumers Act, 2016”.
	Regulation 364/16 made under “Ontario Rebate for Electricity Consumers Act, 2016”.

- End of Document -

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Exhibit "R"

IESO Market Manual entitled "IESO Charge Types and Equations" dated November 29, 2023

Exhibit "R"

to the Affidavit of Robin Doolittle

Sworn before me on October 29, 2025, in accordance with O. Reg. 431/20, Administering Oath or Declaration Remotely



Commissioner for Taking Affidavits
(or as may be)

October 29, 2025

Keith Edward Hickey, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.

Expires June 24, 2027.

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IMP_LST_0001

LIST



IESO Charge Types and Equations

Issue 84.0

This document enumerates the various charge types and equations used in the IESO settlements process for IESO-Administered markets that are subject to a functional deferral, and those that are NOT subject to a functional deferral.

Disclaimer

The posting of documents on this Web site is done for the convenience of *market participants* and other interested visitors to the *IESO* Web site. Please be advised that, while the *IESO* attempts to have all posted documents conform to the original, changes can result from the original, including changes resulting from the programs used to format the documents for posting on the Web site as well as from the programs used by the viewer to download and read the documents. The *IESO* makes no representation or warranty, express or implied, that the documents on this Web site are exact reproductions of the original documents listed. In addition, the documents and information posted on this Web site are subject to change. The *IESO* may revise, withdraw or make final these materials at any time at its sole discretion without further notice. It is solely your responsibility to ensure that you are using up-to-date documents and information.

This document may contain a summary of a particular *market rule*. Where provided, the summary has been used because of the length of the *market rule* itself. The reader should be aware, however, that where a *market rule* is applicable, the obligation that needs to be met is as stated in the "Market Rules". To the extent of any discrepancy or inconsistency between the provisions of a particular *market rule* and the summary, the provision of the *market rule* shall govern.

See also "Notice to *Electricity Storage Participants"* in Section 2.2.

Document ID	IMP_LST_0001
Document Name	IESO Charge Types and Equations
Issue	Issue 84.0
Reason for Issue	Updated for Baseline 50.1
Effective Date	November 29, 2023

Document Change History

Issue	Reason for Issue	Date
• For change history prior to Issue 22.0, see Issue 29.0 of the CT&E. • For change history for Issue 22.0 to Issue 29.0, see Issue 38.0 of the CT&E. • For change history for Issue 30.0 to Issue 49.0, See Issue 59.0 of the CT&E		
50.0	Updated for Baseline 30.0	September 11, 2013
51.0	Updated for Baseline 30.1	December 4, 2013
52.0	Update for Baseline 31.1	June 4, 2014
53.0	Update for Baseline 32.0	September 10, 2014
54.0	Updated for Baseline 33.0	March 4, 2015
55.0	Updated for Baseline 34.0	September 9, 2015
56.0	Updated for Baseline 34.1	December 2, 2015
57.0	Updated for Baseline 35.0	March 2, 2016
58.0	Updated for Baseline 35.1	June 1, 2016
59.0	Updated for Baseline 36.0	September 14, 2016
60.0	Updated for Baseline 36.1	December 7, 2016
61.0	Updated for Baseline 37.0	March 1, 2017
62.0	Updated for Baseline 38.1	December 6, 2017
63.0	Updated for Baseline 39.0	March 7, 2018
64.0	Updated for Baseline 40.0	September 12, 2018
65.0	Updated for Baseline 41.0	March 6, 2019
66.0	Updated for Baseline 41.1	June 5, 2019
67.0	Updated for Baseline 42.0	September 11, 2019
68.0	Updated for Baseline 42.1	December 4, 2019
69.0	Updated in advance of Baseline 43.1	April 23, 2020
70.0	Updated in advance of Baseline 43.1 for the commitment period beginning May 1, 2021	May 4, 2020
71.0	Updated for Baseline 44.0	September 16, 2020
72.0	Updated in advance of Baseline 44.1	November 25, 2020
73.0	Updated for Baseline 44.1	December 2, 2020

Issue	Reason for Issue	Date
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Related Documents

Document ID	Document Title
MDP_PRO_0033	Market Manual 5: Settlements, Part 5.5: Physical Markets Settlement Statements

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Reference (Section and Paragraph)	Description of Change
2.1	Edited CACP, $CBOC_{k,}$ $CAEO^{m}_{h,k,}$ $CICAP^{m}_{h,k}$,$DREBQ^{m}_{h,k,}$ DRSQTY, HDRDC, HDRBP, $OCMW_{k,}$ RAC^{m}_{k} to reflect administrative updates related to the Capacity Auction
2.2	Edited charge types 1314-1322, and 1350-1351 to reflect administrative updates related to the Capacity Auction

1. Introduction

1.1 Purpose

The purpose of this document is to provide the reader with the formulas and variable definitions behind each different *charge type* implemented in the *IESO Settlements* process including tax treatment. Furthermore, this document relates each *charge type* to the high-level description of the *settlement amount* within the *IESO market rules* and, where applicable, notes any aspects of the implementation of the *charge type* itself.

1.2 Scope

This document provides the formulas and the HST Tax treatment for each *charge type* implemented in the *IESO Settlements* System and those *charge types* which are currently the subject of a Functional Deferral. This document does not, however, provide the format of the information provided to *market participants* on *settlement statements* with respect to each *charge type*. For more information on these topics, the reader is directed to the following Technical Interface Document - "Format Specification for Settlement Statement Files and Data Files".

1.3 Tax Treatment

The *IESO* is a registrant for purposes of the *Excise Tax Act* and all or substantially all of the supplies made by the *IESO* are taxable for GST/HST purposes.

The *IESO* administers the *IESO-administered markets* in compliance with the current provisions of the *Excise Tax Act* and the published rulings, administrative policies, and assessing practices of the Canada Revenue Agency. The *IESO* conducts regular tax reviews with its advisors to ensure that transactions within the *IESO-administered markets* comply with the foregoing.

Market participants should consult their own legal and tax advisors for advice with respect to the tax consequences of transactions in the *IESO-administered markets*.

1.4 Who Should Use This Document

This document is intended for *market participants* in the *IESO-administered markets* who are seeking information regarding the calculations of *settlement amounts* related to each *charge type*. Depending on the activity of the *market participant* in the various *IESO-administered markets*, these *charge types* may have varying degrees of relevance to each *market participant* with respect to their financial settlements.

1.5 Conventions

Usage of an italicized term shall take on the meaning ascribed to that term in the *IESO market rules*.

Unless otherwise noted, usage of variable subscripts and superscripts within this document shall mirror the same usage with in Chapter 9 of the *IESO market rules*. One notable exception is the usage of notation to sum across *settlement amounts* for *charge type* "c". This is further noted in Section 2.2 of this document.

1.6 How This Document is Organized

This document is divided in 6 major subsections as follows:

Section 2.1: A table containing a description of each variable used within **Section 2.2**.

Section 2.2: A table describing *IESO charge types* and equations that are part of an active *IESO-administered market*.

Section 2.3: This section contains a description of rounding conventions for variables described in **Section 2.1**.

Section 2.4: This section contains a description of rounding conventions for *charge type* calculations described in **Section 2.2**.

Section 2.5: This section provides a description of *physical bilateral contract quantities*, their usage by the settlements system, and their use by *market participants* as a vehicle for transferring components of *hourly uplift.*

Section 2.6: This section describes how Day-Ahead import, export and linked wheel transactions are subject to an "Offer Price Test" in order to determine if they are exempt from the Day-Ahead Failure Charges (*charge types*, 1135, 1136 and 1134).

– End of Section –

2. IESO Charge Types and Equations that are Part of an Active IESO-Administered Market

2.1 Variable Descriptions

The following table contains descriptions of each variable used within Section 2.2, describing *IESO charge types* and equations that are part of an active *IESO-administered market*.

Key to the Table Below				
Variable used within Section 2	**Data Description**	**Description**	**Market Rules Reference**	**Relation to the corresponding variable description within the IESO Market Rules**
This column denotes the abbreviated name of each variable used within Section 2.2.	The full name of each variable used within Section 2.2.	A brief description of each variable used within the formulas illustrated within Section 2.2.	The relevant reference to the variable in question within the *IESO market rules*. The format of each reference is: [Chapter] [Section no.] e.g. Chapter 9 Section 3.1.6 would appear as: 9.3.1.6	This section notes any aspects of the implementation of the variable within the *IESO settlements* process which are otherwise not described in the *IESO market rules* – OR – refers the reader to the appropriate documentation.

Key to the Table Below				
Variable used within Section 2	**Data Description**	**Description**	**Market Rules Reference**	**Relation to the corresponding variable description within the IESO Market Rules**
AAD	Adjustment Account Disbursement	The total dollar value of all disbursements from the *IESO adjustment account* authorized by the *IESO Board* in the current *energy market billing period*.	9.6.18.6	Same as *IESO* market rules.
$AQEI_{k,h}^{m,t}$	Allocated Quantity of Energy Injected	Allocated quantity in MWh of *energy* injected by *market participant* 'k' at *RWM* 'm' in *metering interval* 't' of *settlement hour* 'h'.	9.3.1.9	Represents only those quantities derived from loss-adjusted and totalized *metering data*. Quantities derived from *interchange schedule data* is captured in the variable SQEI (see below).
$AQEW_{k,h}^{m,t}$	Allocated Quantity of Energy Withdrawn	Allocated quantity in MWh of *energy* withdrawn by *market participant* 'k' at *RWM* 'm' in *metering interval* 't' of *settlement hour* 'h'.	9.3.1.9	Represents only those quantities derived from loss-adjusted and totalized *metering data*. Quantities derived from *interchange schedule data* is captured in the variable SQEW (see below).
$AQOR_{r,k,h}^{m,t}$	Allocated Quantity of Operating Reserve	Allocated quantity in MW of *class r reserve* for *market participant* 'k' at *RWM* 'm' in *metering interval* 't' of *settlement hour* 'h'.	9.3.1.9	Same as *IESO market rules* and equivalent to DQSR (see below).

Key to the Table Below				
Variable used within Section 2	**Data Description**	**Description**	**Market Rules Reference**	**Relation to the corresponding variable description within the IESO Market Rules**
BE	Energy Offers	A matrix of 'n' *price-**quantity** pairs* offered by *market participant* 'k' to supply *energy* during *settlement hour* 'h'. *Offer prices* in this matrix may be altered to a **"lower limit"** for the purposes of calculating *charge type* 105 (Congestion Management *Settlement* Credit for *Energy)* where any such *offer price*: 1) Is associated with a *generation facility* located within Ontario; or imports and 2) Is less than a specified **"lower limit"** where such limit is the lesser of $0.00/MWh and the *energy market price* for the applicable *dispatch interval*. The situational criteria and threshold for applying such adjustments are further described in *IESO market rules* section 9.3.5.6. and 9.3.5.7.	9.3.5.2, 9.3.5.6 and 9.3.5.7	Same as *IESO market rules*.
BL	Energy Bids	A matrix of 'n' *price-quantity pairs* bid by *market participant* 'k' to withdraw *energy* by a *dispatchable load* during *settlement hour* 'h'.	9.3.5.2	Same as *IESO market rules*.

Key to the Table Below				
Variable used within Section 2	**Data Description**	**Description**	**Market Rules Reference**	**Relation to the corresponding variable description within the IESO Market Rules**
BR_r	Operating Reserve Offers	A matrix of n *price-quantity pairs* offered by *market participant* 'k' to supply class r *operating reserve* during *settlement hour* 'h'.	9.3.5.2	Same as *IESO market rules*.
$BCQ_{s,k,h}{}^{m,t}$	Physical Bilateral Contract Quantity of Energy bought	*Physical bilateral contract quantity* of *energy* in MWh bought by *buying market participant* 'k' from *selling market participant* 's' at *RWM* or *intertie metering point* 'm' for each *metering interval* 't' in *settlement hour* 'h'.	9.3.1.6	Same as *IESO market rules*.
$BCQ_{k,b,h}{}^{m,t}$	Physical Bilateral Contract Quantity of Energy sold	*Physical bilateral contract quantity* of *energy* in MWh sold by *selling market participant* 'k' to *buying market participant* 'b' at *RWM* or *intertie metering point* 'm' for each *metering interval* 't' in *settlement hour* 'h'.	9.3.1.6	Same as *IESO market rules*.
$CACP^z$	Capacity Auction Clearing Price	The *capacity auction clearing price* (in $/MW per day) for the relevant *trading day* in electrical zone 'z'.	9.3.1.10	Same as *IESO market rules*
$CACP^z{}_h$	Hourly Capacity Auction Clearing Price	The *capacity auction clearing price* for *settlement hour* 'h' (in $/MW per hour) within the *availability window* in electrical zone 'z', determined by taking the *capacity auction clearing price* for the applicable *obligation period* and electrical zone and dividing by the number of *settlement hours* within the	9.3.1.10	Same as *IESO market rules*

Key to the Table Below				
Variable used within Section 2	**Data Description**	**Description**	**Market Rules Reference**	**Relation to the corresponding variable description within the IESO Market Rules**
		availability window of all *trading days* within the *obligation period.*		
$CAEO^{m}_{h,k}$	Capacity Auction Energy Offer	The quantity of *auction capacity* for *settlement hour* 'h' (in MW) made available by *capacity auction resource* for *capacity market participant* 'k' at *delivery point* or *intertie metering point* 'm' in the relevant *settlement hour* of the *availability window* determined as the lesser of the *resource's energy offers* submitted in the day-ahead commitment process, pre-dispatch, and *real-time energy market*, as applicable.	9.3.1.10	Same as *IESO market rules.*
$CARC_{k^{m}}$	Capacity Auction Registered Capability	The quantity of *energy* (in MW) of the *hourly demand response resource's demand response contributors* total registered capability for *capacity market participant 'k'* at *delivery point* 'm', as registered with the *IESO* in accordance with the applicable *market manual*	9.3.1.10	Same as *IESO market rules.*
$CBOC^{m}_{k}$	Buy-out Capacity	The buy-out capacity is an amount (in MW) by which the *capacity obligation* for the *obligation period* for *capacity auction resource* for *capacity market participant* 'k' at *delivery point* or *intertie metering point* 'm' is being reduced as per the *capacity market participant's* election pursuant to section 4.7J.3 of Chapter 9.	9.3.1.10	Same as *IESO market rules*

Key to the Table Below				
Variable used within Section 2	**Data Description**	**Description**	**Market Rules Reference**	**Relation to the corresponding variable description within the IESO Market Rules**
CBMP_k	Total net volume of electricity withdrawn from the *IESO-controlled grid* by applicable Class B market participant or licensed distributor that is also a *market participant* for the month	The total net volume of electricity withdrawn from the *IESO-controlled grid* by applicable Class B market participant (as that term is defined in the regulation) or licensed distributor that is a *market participant* 'k' for the month.	N/A	N/A – See regulations.
CBRR	Global adjustment Class B recovery rate	Global Adjustment Class B recovery rate for the month per Ontario Regulation 429/04.	N/A	N/A – See regulations.
$\mathrm{CCO}^{\mathrm{m}}{}_{\mathrm{k,h}}$	Capacity Obligation (MW)	The *capacity obligation* (in MW) for the *obligation period* per *capacity auction resource* for *capacity market participant* 'k' at *delivery point* or *intertie metering point* 'm' in the relevant *settlement hour 'h'*, as may be adjusted pursuant to the *market rules*..	9.3.1.10	Same as *IESO market rules.*
CGC	Submitted Combined Guaranteed Costs	A financial amount consisting of fuel cost components defined on a *per-start* basis for a given *generation unit* calculated in a manner consistent with the applicable *market manual*, and encompassing the following elements: 1) Fuel and operation and maintenance (O&M) costs associated with unit synchronization to the *IESO-controlled grid* for a given start-up event (costs submitted via Online *IESO*).	9.4.7B	Same as *IESO market rules*.

Key to the Table Below				
Variable used within Section 2	**Data Description**	**Description**	**Market Rules Reference**	**Relation to the corresponding variable description within the IESO Market Rules**
		2) Fuel and O&M costs associated with moving the *generation unit* from a valid start to its *minimum loading point* (costs submitted via Online *IESO*).		
$\mathrm{CICAP}^{\mathrm{m}}{}_{\mathrm{k}}$	Capacity Auction *Cleared ICAP*	The *cleared ICAP* (in MW) for *capacity auction resource* at *delivery point* or *intertie metering point* 'm' for *capacity market participant* 'k' in the applicable *obligation period*, as determined in accordance with the applicable *market manual*	9.3.1.10	Same as *IESO market rules*
CNPF_{tm}	Capacity Auction Non-Performance Factor	For a given *energy market billing period,* the non-performance factor as listed in Section 7.1 of Market Manual 12.	9.3.1.10	Same as *IESO market rules*
$\mathrm{DA_BE}_{\mathrm{k,h}}{}^{\mathrm{m,t}}$	*Energy Offer* submitted into the *schedule of record at a delivery point*	*Energy offers* submitted in day-ahead, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *delivery point* 'm' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered price in each *price-quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2.	9.3.1.2B.7	Same as *IESO market rules.*
$\mathrm{DA_BE}_{\mathrm{k,h}}{}^{\mathrm{i,t}}$	*Energy Offer* submitted into the *schedule of record at a intertie metering point*	*Energy offers* submitted in day-ahead, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *intertie metering point* 'i' during *metering*	9.3.8A.2B and 9.3.8B.2	Same as *IESO market rules*

Key to the Table Below				
Variable used within Section 2	**Data Description**	**Description**	**Market Rules Reference**	**Relation to the corresponding variable description within the IESO Market Rules**
		interval 't' of *settlement hour* 'h' arranged in ascending order by the offered price in each *price-quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2.		
$DA_BL_{k,h}^{i,t}$	*Energy* Bids submitted into the *schedule of record*	Energy bids submitted in day-ahead, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered price in each *price-quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2.	9.3.1.2B.7 and 9.3.8D.2	Same as *IESO market rules*
DA_CGC	Submitted Day-Ahead Combined Guaranteed Costs	EFFECTIVE OCTOBER 13, 2011, THIS VARIABLE IS NO LONGER USED IN THE CALCULATION OF ANY SETTLEMENT. A financial amount consisting of fuel cost components defined on a *per-start* basis for a given *generation unit* calculated in a manner consistent with the applicable *market manual*, and encompassing the following elements: 1) Fuel and operation and maintenance (O&M) costs associated with unit synchronization to the *IESO-controlled*	9.4.7D.1	Same as *IESO market rules*

Key to the Table Below				
Variable used within Section 2	**Data Description**	**Description**	**Market Rules Reference**	**Relation to the corresponding variable description within the IESO Market Rules**
		grid for a given start-up event (costs submitted via *IESO* Gateway). 2) Fuel and O&M costs associated with moving the *generation unit* from a valid start to its *minimum loading point* (costs submitted via *IESO* Gateway).		
$DA_DQSI_{k,h}^{m,t}$	*Schedule of Record* Dispatch Quantity of Energy Scheduled for Injection at a delivery point	Day-ahead constrained quantity scheduled for injection by *market participant* 'k' at *delivery point* 'm' during *metering interval* 't' of *settlement hour* 'h'.	9.3.1.2A	Same as *IESO market rules.*
$DA_DQSI_{k,h}^{i,t}$	*Schedule of Record* Dispatch Quantity of Energy Scheduled for Injection at an intertie metering point	Day-ahead constrained quantity scheduled for injection by *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h'.	9.3.1.2A	Same as *IESO market rules.*
$DA_DQSW_{k,h}^{i,t}$	*Schedule of Record* Dispatch Quantity of Energy Scheduled for Withdrawal	Day-ahead constrained quantity scheduled for withdrawal by *market participant* 'k' at *intertie metering point* 'i' during metering interval 't' of settlement hour 'h'.	9.3.1.2A	Same as *IESO market rules.*
$DA_ELMP_{h}^{m,t}$	*Pre-dispatch* constrained schedule price for an *intertie metering point* in the export zone	Day-ahead constrained schedule intertie price at the *delivery point* 'm' of the sink for the export transaction during *metering interval* 't' of *settlement hour* 'h'.	9.3.1.2A	Same as *IESO market rules.*
$DA_ILMP_{h}^{m,t}$	*Pre-dispatch* constrained schedule price for an *intertie*	Day-ahead constrained schedule intertie price at the *delivery point* 'm' of the source for the	9.3.1.2A	Same as *IESO market rules.*

Key to the Table Below				
Variable used within Section 2	**Data Description**	**Description**	**Market Rules Reference**	**Relation to the corresponding variable description within the IESO Market Rules**
	metering point in the import zone	import transaction during *metering interval* 't' of *settlement hour* 'h'.		
$DA_SNLC_{k,h}{}^{m}$	Speed-no-load costs submitted into the *schedule of record at a delivery point*	As-offered *speed-no-load cost* associated with *three-part offers* for a given *settlement hour* 'h' for *market participant* 'k' at *delivery point* 'm'.	9.3.1.2B.7	Same as *IESO market rules.*
$DA_SNLC_{k,h}{}^{p}$	Speed-no-load costs submitted into the *schedule of record at a pseudo-unit*	As-offered *speed-no-load cost* associated with *three-part offers* for a given *settlement hour* 'h' for *market participant* 'k' at *pseudo-unit* 'p'.	9.3.1.2B.7	Same as *IESO market rules.*
$DA_SUC_{k,h}{}^{m}$	Start-up costs submitted into the *schedule of record at a delivery point*	As-offered *start-up cost* associated with *three-part offers* for a given *settlement hour* 'h' for *market participant* 'k' at *delivery point* 'm' where *settlement hour* 'h' is the initial hour in the DACP start event.	9.3.1.2B.7	Same as *IESO market rules.*
$DA_SUC_{k,h}{}^{p}$	Start-up costs submitted into the *schedule of record at a pseudo-unit*	As-offered *start-up cost* associated with *three-part offers* for a given *settlement hour* 'h' for *market participant* 'k' at *pseudo-unit* 'p' where *settlement hour* 'h' is the initial hour in the DACP start event.	9.3.1.2B.7	Same as *IESO market rules.*
$DIPC_{k,h}{}^{m,t}$	Derived Interval Price Curve	*Energy price curves* derived per interval from submitted hourly day-ahead PSU *energy offers*, represented as a N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *delivery point* 'm' (where 'm' is a CT or ST delivery point) during	9.3.1.11	Same as *IESO market rules.* Refer to Market Manual 9.5, Appendix B for a detailed description of DIPC.

Key to the Table Below				
Variable used within Section 2	**Data Description**	**Description**	**Market Rules Reference**	**Relation to the corresponding variable description within the IESO Market Rules**
		metering interval 't' of *settlement hour* 'h' arranged in ascending order by the offered price in each *price quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2.		
$DIGQ_{k,h}^{m,t}$	Derived Interval Guaranteed Quantity	Portion of the day-ahead constrained quantity scheduled for injection that is eligible for DA-PCG for market participant 'k' at pseudo unit 'p' during metering interval 't' of settlement hour 'h'	9.3.1.11	Same as *IESO market rules.* Refer to Market Manual 9.5, Appendix C for a detailed description of DIGQ.
$DQSI_{k,h}^{m,t}$	Dispatch Quantity of Energy Scheduled for Injection	Dispatch quantity of energy scheduled for injection in the real-time schedule by market participant 'k' at location 'm' in metering interval 't' of settlement hour 'h'.	9.3.1.3 and 9.3.1.4A	Same as *IESO market rules.* N.B. Location m is further subject to the functional deferral described in Section 3.1.4A of Chapter 9 of the market rules (ref. 9.3.1.4A).
$DQSR_{r,k,h}^{m,t}$	Dispatch Quantity Schedule of Operating Reserve	Dispatch quantity schedule of class r reserve for market participant 'k' at location 'm' in metering interval 't' of settlement hour 'h'.	9.3.1.4 and 9.3.1.4A	Same as *IESO market rules.* N.B. Location m is further subject to the functional deferral described in Section 3.1.4A of Chapter 9 of the market rules (ref. 9.3.1.4A).
$DQSW_{k,h}^{m,t}$	Dispatch Quantity of Energy Scheduled for Withdrawal	Dispatch quantity of energy scheduled for withdrawal in the real-time schedule by market participant 'k' at location 'm' in metering interval 't' of settlement hour 'h'.	9.3.1.3 and 9.3.1.4A	Same as *IESO market rules.* N.B. Location m is further subject to the functional deferral described in Section 3.1.4A of Chapter 9 of the market rules (ref. 9.3.1.4A).

Key to the Table Below				
Variable used within Section 2	**Data Description**	**Description**	**Market Rules Reference**	**Relation to the corresponding variable description within the IESO Market Rules**
DRACP	Demand Response Auction Clearing Price	The *demand response auction clearing price* for the *commitment period* and zone.	N/A	Refer to Market Manual 5.5
$DRACP_h$	Hourly Demand Response Auction Clearing Price	The *demand response auction clearing price* for the *commitment period* and zone divided by the hours of availability for a day.	N/A	Refer to Market Manual 5.5
$DRBOC_k$	Demand Response Buy-Out Capacity	The buy-out capacity is an amount that is being reduced from the *demand response capacity obligation* for *demand response market participant* 'k'.	N/A	Refer to Market Manual 5.5
$DRCO_k$	Demand Response Capacity Obligation (MW)	The *demand response capacity obligation* amount for the *commitment period* and zone for *demand response market participant* 'k'. The initial capacity obligation is acquired through the *demand response auction* and subject to being reduced via the buy-out process.	N/A	Refer to Market Manual 5.5

Key to the Table Below				
Variable used within Section 2	**Data Description**	**Description**	**Market Rules Reference**	**Relation to the corresponding variable description within the IESO Market Rules**
$DREBQ^{m}{}_{k,h}$	Demand Response Energy Bid Quantity	The quantity (in MW) of *auction capacity* made available by an *hourly demand response resource* or *capacity dispatchable load resource* for *capacity market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' of the *availability window*, determined as the lesser of he *resource's energy bids* submitted in the day-ahead commitment process, pre-dispatch, and *real-time energy market*, as applicable, and where such value exceeds the $CARC_k{}^{m}$ for the resource in the relevant *energy market billing,* the $DREBQ^{m}{}_{k,h}$ shall equal such $CARC_k{}^{m}$	9.3.1.10	Same as *IESO market rules*
DRNPF	Demand Response Non-Performance Factor	The non-performance factor as listed in Section 7.1 of Market Manual 12 that corresponds and applies to the month being settled.	N/A	Refer to Market Manual 5.5
$DRSQty^{m}{}_{k,h}$	Demand Response Scheduled Quantity	The quantity of *energy* (in MW) scheduled for withdrawal in the *real time market* by *market participant* 'k' at *delivery point* 'm' for an *hourly demand response resource* in *settlement hour* 'h' of the *availability window*, as described in the *real time schedule*.	9.3.1.10	Same as *IESO market rules*
EEQ	Excluded Energy Quantity	The total volume of *energy* (MWh) supplied to Fort Frances Power Corporation	N/A – subject to regulations made	N/A – See regulations.

Key to the Table Below				
Variable used within Section 2	**Data Description**	**Description**	**Market Rules Reference**	**Relation to the corresponding variable description within the IESO Market Rules**
		Distribution Inc. by Abitibi-Consolidated Inc. during the month.	pursuant to Bill 100.	
$EGEI_k$	Embedded Generator Energy Injection	The total volume of *energy* (MWh) supplied by *embedded generator*s during the month to *distributors* who are *market participants* and to all embedded distributors to whom the *market participant* 'k' is the host *distributor*, adjusted for losses as required by the *OEB*, Retail Settlement Code.	N/A – subject to regulations made pursuant to Bill 100.	N/A – See regulations.
$EIM_{k,h}$	Operating Profit Function for the IMPORT of Energy under the Intertie Offer/Bid Guarantee Settlement Credit	This Operating Profit function is used for the calculation of the Intertie Offer/Bid Guarantee Settlement Credit (IOBG) with respect the IMPORT of *energy*.	9.3.8A	$EIM_{k,h}$ IS NOT A VARIABLE $EIM_{k,h}$ is the output of a particular usage of the Operating Profit (OP) function defined within Chapter 9, Section 3.8A. $EIM_{k,h}$ Input variables into the Operating Profit (OP) Function include: MQSI, EMP, and BE.
$EMP_h^{i,t}$	5-minute Energy Market Price at the Interties	Energy *market price* applicable to *intertie metering point* 'i' in *metering interval* 't' of *settlement hour* 'h'.	9.3.1.3	Same as *IESO market rules*.
$EMP_h^{m,t}$	5-minute Energy Market Price within Ontario	Energy *market price* applicable to *RWM* 'm' in *metering interval* 't' of *settlement hour* 'h'.	9.3.1.3	Same as *IESO market rules*.

Key to the Table Below				
Variable used within Section 2	**Data Description**	**Description**	**Market Rules Reference**	**Relation to the corresponding variable description within the IESO Market Rules**
$EMP_h^{REF,t}$	5-minute Energy Market Reference Price	Reference energy *market price* used to value losses in the calculation of the *Transmission Charge Reduction Fund*[1] during in *metering interval* 't' of *settlement hour* 'h'.	9.3.1.3 and 9.3.6.2	Same as *IESO market rules*.
ETS	Export Transmission Service Tariff Rate	Export Transmission Service Tariff Rate in units of $/MWh.	N/A	Subject to the OEB "Ontario Transmission Rate Order".
FP_h^m	Fixed Energy Rate	A fixed *energy* rate for all *metering intervals* in *settlement hour* 'h'.	N/A – subject to regulations made pursuant to *Ontario Energy Board Act, 1998* until March 31, 2005 and by the *OEB* under such regulations commencing April 1, 2005.	N/A – See regulations.
FPC_h^m	Rate for a designated group of *charge types* (see description of *charge type* 141)	This variable is reserved for *charge type* 141 and applies with respect to charges for the period commencing December 1, 2002 and ending March 31, 2005. See Ontario Regulation 436/02 and Ontario Regulation 98/05.	N/A – subject to regulations made pursuant to *Ontario Energy Board Act, 1998*.	N/A – See regulations

1 *Market Rules* ref.: Section 3.6.2 of Chapter 9.

Key to the Table Below				
Variable used within Section 2	**Data Description**	**Description**	**Market Rules Reference**	**Relation to the corresponding variable description within the IESO Market Rules**
$GA_AQEW_{g,k,h,M}{}^{m,t}$	Allocated Quantity of Energy Withdrawn for elements of the Global Adjustment distribution	Allocated quantity in MWh of *energy* withdrawn by *market participant* or Distributor 'k*'* at *RWM* 'm' in *metering interval* 't' of *settlement hour* 'h' in month 'M' for element "g" Where 'g' is 1 for Class A Market Participant or Consumer load, and 2 for *energy* withdrawn by Generator 'k' in the course of providing Ancillary Services.		
GAR_B	Global Adjustment Rate for Class B	GA Class B Rate.	N/A	N/A – See regulations.
GRP	Generator Regulated Price	A regulated price ($/MWh) with respect to output of OPG's regulated generating stations, set by the *OEB*.	N/A – subject to regulation by the Ontario Energy Board.	N/A – See regulations
$GSSR_AQEW_{k,h}{}^{m,t}$	Qualified Allocated Quantity of Energy Withdrawn for Generation Station Service Reimbursement (GSSR)	Qualified Allocated quantity in MWh of *energy* withdrawn by *market participant* 'k*'* at *RWM* 'm' in *metering interval* 't' of *settlement hour* 'h' by an eligible generation facility	9.2.1A.9	
$HDRDC^{m}{}_{k,h}$	Measured hourly *demand response capacity*	The delivered capacity (in MWh) by *hourly demand response resource* for *capacity market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' within the activation	9.3.1.10	Same as *IESO market rules*

Key to the Table Below				
Variable used within Section 2	**Data Description**	**Description**	**Market Rules Reference**	**Relation to the corresponding variable description within the IESO Market Rules**
		window of the applicable test activation, calculated as follows: Min (curtailed $MW^{m}_{k,h}$, $\sum^{12}_{t=1}$ (Min ($TBQ^{m}_{k,h}$, $CARC^{m}_{k}$, $CCO^{m}_{k,h}$)) - $DQSY^{m,t}_{k,h}$/12)) Where: (a) "Curtailed $MW^{m}_{k,h}$" is the difference (in MWh) between baseline value, calculated in accordance with the applicable *market manual*, and actual consumption measurement data by *capacity market participant* 'k' at *delivery point* 'm' for an *hourly demand response resource* for *settlement hour* 'h', as calculated in accordance with the applicable *market manual*. (b) "$TBQ^{m}_{k,h}$" is the offered quantity of *energy* (in MW) contained in the last lamination of the *price quantity pair* of the *energy bid* submitted in the *real time market* by *capacity market participant* 'k' at *delivery point* 'm' for an *hourly demand response resource* in *settlement hour* 'h'		

Key to the Table Below				
Variable used within Section 2	**Data Description**	**Description**	**Market Rules Reference**	**Relation to the corresponding variable description within the IESO Market Rules**
$HDRBP^{m}_{k,h}$	HDR Bid Price	The price component (in $) of the *energy bid* submitted in the *real time market* for *hourly demand response resource* by *capacity market participant* 'k' at *delivery point* 'm' for *settlement hour* 'h' within the *availability window*	9.3.1.10	Same as *IESO market rules.*
HDRTAPR	Out of Market Test Activation Payment Rate	The out of market test activation rate (in $), as set out in the applicable *market manual.*	9.3.1.10	Same as *IESO market rules*.
$HOEP_h$	Hourly Ontario Energy Price	*Hourly Ontario Energy Price* in *settlement hour* 'h'.	9.3.1.3	Same as *IESO market rules*.
$IOG_FV_{k,h}{}^{i}$	IOG Floor Value	EFFECTIVE OCTOBER 13, 2011, THIS VARIABLE IS NO LONGER USED IN THE CALCULATION OF ANY SETTLEMENT. The IOG_FVk,hi is a floor value (in dollars to the nearest cent) derived from: • The day-ahead offer prices for the import transaction submitted by the *market participant* over the range of the *pre-dispatch of record* constrained quantity scheduled for that import transaction; and • Real-*time* offer prices for the import transaction at the corresponding location in the corresponding *settlement hour* for any additional	9.3.8A.8	Same as *IESO market rules* See Chapter 9, Section 3.8A.8 for details concerning its formulation.

Key to the Table Below				
Variable used within Section 2	**Data Description**	**Description**	**Market Rules Reference**	**Relation to the corresponding variable description within the IESO Market Rules**
		energy scheduled above and beyond the *pre-dispatch of record* constrained quantity scheduled for that import transaction: **NOTE:** The $IOG_FV_{k,h}{}^{i}$ is formulated in the manner described in Chapter 9, Section 3.8A.8 of the *IESO market rules* and is used in the formulation of the intertie offer guarantee adjustment (see also, Section 2.2 entry for *charge type* 1137 within this document).		
$LCD_{k,h}{}^{m}$	Line Connection Demand (KW)	Billing Demand for Line Connection Transmission Service (KW) for *transmission customer* 'k' at transmission delivery point 'm' during *settlement hour* 'h' in which $LCD_{k,h}{}^{m}$ denotes the non-coincident peak demand for the month.	N/A	Subject to the OEB "Ontario Transmission Rate Order".
$MAX_CAP_{k,h}{}^{m,t}$	Maximum Capability	The maximum limit used in determining the real-time schedule in the dispatch scheduling and pricing process as described in Chapter 7, Appendix 7.5 for each interval	9.3.4.2	
MDCAA	Monthly deferred Class A amount to be recovered	The monthly deferred Class A amount to be recovered which equals one twelfth of the total Global Adjustment allocated to Class A customers that was deferred in April, May and June of 2020.	N/A	N/A – See regulations.

Key to the Table Below				
Variable used within Section 2	**Data Description**	**Description**	**Market Rules Reference**	**Relation to the corresponding variable description within the IESO Market Rules**
MDCBA	Monthly deferred Class B amount to be recovered	The monthly deferred Class B amount to be recovered equals one twelfth of the total Global Adjustment allocated to Class B customers that was deferred in April, May and June of 2020.	N/A	N/A – See regulations.
MC_h^m	Minimum Consumption	Used for the OR non-accessibility charges and the calculation of the self-induced dispatchable load CMSC clawback under Business Rule 2. The minimum consumption is equal to the quantity in the price quantity pair where the bidding price is MMCP (i.e., $2000) at *RWM metering point* 'm' for settlement hour 'h'.	9.3.5.1A, 9.3.4.2	
MI	Ordered matrix of $MQSI_{k,h}^{i,t}$ and corresponding IOG *settlement amounts*	Used for the calculation of the IOG OFFSET *settlement amount.* A matrix of X pairs of *market schedule* quantities scheduled for injection by *market participant* 'k' at all *intertie metering points* 'i' in *metering interval* 't' of *settlement hour* 'h' ($MQSI_{k,h}^{i,t}$) paired with the corresponding component of the intertie offer guarantee settlement credit for each *intertie metering point* 'i'. See equation in Chapter 9, Section 3.8A.4 of the *IESO market rules* for further details.	9.3.8A.4	Same as *IESO market rules*.
$MLP_{k,h}^{m,t}$	Minimum Loading Point	Minimum output of *energy* the *market participant* 'k' at *delivery point* 'm' can	9.3.1.2B.7	Same as *IESO market rules.*

Key to the Table Below				
Variable used within Section 2	**Data Description**	**Description**	**Market Rules Reference**	**Relation to the corresponding variable description within the IESO Market Rules**
		maintain without ignition support in *metering interval* 't' of *settlement hour* 'h'.		
$MLP_CONS_{k,h}^{m,t}$	Minimum Loading Point for a steam turbine resource or a combustion turbine resource associated to a pseudo unit	Minimum output of *energy* the *market participant* 'k' at *delivery point* 'm' can maintain without ignition support in *metering interval* 't' of *settlement hour* 'h'.	9.3.1.2B.7	Same as *IESO market rules.* Refer to Market Manual 9.4, Section 4.1.2.2 for a detailed description of constraints applied for PCG eligible combined cycle plants.
$MQSI_{k,h}^{m,t}$	Market Quantity Scheduled for Injection	Market quantity scheduled for injection in the *market schedule* by *market participant* 'k*'* at *RWM* or *intertie metering point* 'm' in *metering interval* 't' of *settlement hour* 'h'.	9.3.1.3	Same as *IESO market rules*.
$MQSI\{adj\}_{k,h}^{m,t}$	Adjusted Market Quantity Scheduled for Injection	EFFECTIVE OCTOBER 13, 2011, THIS VARIABLE IS NO LONGER USED IN THE CALCULATION OF ANY SETTLEMENT. Used for the calculation of the IOG OFFSET *settlement amount.* $MQSI\{adj\}_{k,h}^{i,t}$ is each (and where applicable, adjusted) quantity of *energy* scheduled for injection in the *market schedule* by *market participant* 'k' at an *intertie metering point* 'i' in *metering interval* 't' of *settlement hour* 'h' corresponding with each quantity, $MQSI_{x*,k,h}^{i,t}$ in matrix MI, row x*.	9.3.8A.4	Same as *IESO market rules*.

Key to the Table Below				
Variable used within Section 2	**Data Description**	**Description**	**Market Rules Reference**	**Relation to the corresponding variable description within the IESO Market Rules**
$MQSW_{k,h}{}^{m,t}$	Market Quantity Scheduled for Withdrawal	Market quantity scheduled for withdrawal in the *market schedule* by *market participant* 'k' at *RWM* or *intertie metering point* 'm' in *metering interval* 't' of *settlement hour* 'h'.	9.3.1.3	Same as *IESO market rules*.
$NSD_{k,h}{}^{m}$	Network Service Demand (KW)	The Billing Demand for Network Transmission Service (KW) is defined as the higher of: transmission customer coincident peak demand (KW) in the hour of the month when the total hourly demand of all PTS customers is highest for the month; and 85% of the customer peak demand in any hour during the peak period 7 AM to 7 PM (local time) on *business days* defined by the *IESO*. For the purposes of determining business days for calculating transmission charges, the *IESO* uses the holidays identified by the Ontario Energy Board. The peak period hours will be between 0700 and 1900 hours Eastern Standard Time during winter (i.e. during standard time) and 0600 to 1800 hours during summer (i.e. during daylight savings time), in conformance with the meter time standard used by the *IESO* settlement systems.	N/A	Subject to the OEB "Ontario Transmission Rate Order".

Key to the Table Below				
Variable used within Section 2	**Data Description**	**Description**	**Market Rules Reference**	**Relation to the corresponding variable description within the IESO Market Rules**
$OCMW^{i}_{k}$	Over committed MWs	The *over committed capacity* (in MW) of a *generator-backed capacity import resource* for *capacity market participant* 'k' at *intertie metering point* 'i', as determined by the *IESO*.	9.3.1.10	Same as *IESO market rules*.
ONPAO	Ontario Power Generation Non-Prescribed Assets Output	OPG's Non-Prescribed Assets are those generation assets operated and controlled by Ontario Power Generation in service as of January 1, 2006, excluding Lennox Generating Station, that are not prescribed assets under section 78.1 of the *Ontario Energy Board Act, 1998* as amended by the "Electricity Restructuring Act, 2004". ONPAO refers to the generation output from OPG's Non-Prescribed Assets, over each hour of the quarter adjusted to take account of volumes sold through forward contracts in effect as of January 1, 2005. For greater certainty, any output from ONPA resulting from fuel conversion by Ontario Power Generation in ONPA, or incremental output from ONPA resulting from refurbishment or expansion is to be excluded from ONPAO. Incremental Output is defined as: generation output × (new total installed capacity – installed capacity as of January 1, 2006) / new total installed capacity.	N/A	The formula for calculating the OPG Rebate is subject to Ministerial Directive made under Order-in-Council 1062/2006 (May 17, 2006).

Key to the Table Below				
Variable used within Section 2	**Data Description**	**Description**	**Market Rules Reference**	**Relation to the corresponding variable description within the IESO Market Rules**
OP	Operating Profit Function	The Operating Profit function is used for the calculation of the Congestion Management Settlement Credit (CMSC) with respect to constrained on/off payments for *energy*, *operating reserve*. It is also used for the calculation of the Day-Ahead Production Cost Guarantee components, the Day-Ahead Generator Withdrawal Charge, the Day-Ahead Import and Export failure charges, and the Import Offer Guarantee Settlement Credit.	9.3.5.2 and 9.3.8A.2	OP IS NOT A VARIABLE OP is a mathematical function defined within Chapter 9, section 3.5.2. of the *IESO market rules* Input variables include: MQSI, MQSW, SQROR AQEI, AQEW, AQOR SQEI, SQEW, DSQI, DSQW, DSQR DA_DQSI, DA_DQSW, PD_DQSI, PD_DQSW BE, BL, BR_r PD_BE, PD_BL DA_BE, DA_BL EMP MLP, MLP CONS DIPC OPCAP OP is also used within Chapter 9, Section 9.8A.2 of the *IESO market rules* to derive the Energy Import ($EIM_{k,h}$) sub-component of the

Key to the Table Below				
Variable used within Section 2	**Data Description**	**Description**	**Market Rules Reference**	**Relation to the corresponding variable description within the IESO Market Rules**
				Intertie Offer Settlement Credit (IOG) using the following input variables: MQSI BE EMP
$OPCAP_{k,h}^{m,t}$	Operating Capacity	De-rating of the generation unit by *market participant* 'k' at *delivery point* 'm' in *metering interval* 't' of *settlement hour* 'h'.	9.3.1.2B.7	Same as *IESO market rules*.
$OPE\{adj\}_{k,h}^{i}$	Adjusted CMSC component for *energy* used in the DA-Ahead IOG	EFFECTIVE OCTOBER 13, 2011, THIS VARIABLE IS NO LONGER USED IN THE CALCULATION OF ANY SETTLEMENT. This congestion management *settlement* credit *settlement amount* (CMSC) component is specifically used in the calculation of the Day-Ahead IOG for import transactions that are subject to a *constrained-on event* in the *real-time market*. $OPE\{adj\}_{k,h}^{i}$ is an adjusted component of The congestion management *settlement* credit *settlement amount* (CMSC) for *market participant* 'k' at *intertie metering point* 'i' for *settlement hour* 'h' in which the constrained schedule is the lesser of $PDR_DQSI_{k,h}^{i,t}$ or	9.3.8A.2A	'OP' is a mathematical function used within Chapter 9, Section 9.3.8A.2A of the *IESO market rules* to derive Day-Ahead Intertie Offer Guarantee. Please see the *market rules* for information regarding its formulation.

Key to the Table Below				
Variable used within Section 2	**Data Description**	**Description**	**Market Rules Reference**	**Relation to the corresponding variable description within the IESO Market Rules**
		$DQSI_{k,h}^{i,t}$ but in all instances, greater than or equal to $MQSI_{k,h}^{i,t}$.		
ORL	Ontario Power Generation Revenue Limit	For the period May 1, 2006 to April 30, 2007 ORL is equal to $46/ MWh. For the period May 1, 2007 to April 30, 2008 ORL is equal to $47/ MWh. For the period May 1, 2008 to April 30, 2009 ORL is equal to $48/ MWh.	N/A	The formula for calculating the OPG Rebate is subject to Ministerial Directive made under Order-in-Council 1062/2006 (May 17, 2006).
PAA	Pilot Auction Amount	Refers to the Pilot Auction administered by the *Ontario Power Authority* in the first half of 2006. The volume in MWh over each hour in the quarter that is sold by Ontario Power Generation through the PA.	N/A	The formula for calculating the OPG Rebate is subject to Ministerial Directive made under Order-in-Council 1062/2006 (May 17, 2006).
PAORL	Pilot Auction Ontario Power Generation Revenue Limit	For the period May 1, 2006 to April 30, 2007 PAORL is equal to $51/ MWh. For the period May 1, 2007 to April 30, 2008 PAORL is equal to $52/ MWh. For the period May 1, 2008 to April 30, 2009 PAORL is equal to $53/ MWh.	N/A	The formula for calculating the OPG Rebate is subject to Ministerial Directive made under Order-in-Council 1062/2006 (May 17, 2006).

Key to the Table Below				
Variable used within Section 2	**Data Description**	**Description**	**Market Rules Reference**	**Relation to the corresponding variable description within the IESO Market Rules**
PAP	Pilot Auction Price	The weighted average auction price in $/ MWh over each hour of the quarter realized for the PAA by Ontario Power Generation.	N/A	The formula for calculating the OPG Rebate is subject to Ministerial Directive made under Order-in-Council 1062/2006 (May 17, 2006).
$PB_IM_h^t$	Price bias adjustment factor for import transactions	Price bias adjustment factor for import transactions in effect during *metering interval* 't' of *settlement hour* 'h'.	9.3.8C.3	Same as *IESO market rules*
$PB_EX_h^t$	Price bias adjustment factor for export transactions	Price bias adjustment factor for export transactions in effect during *metering interval* 't' of *settlement hour* 'h'.	9.3.8C.5	Same as *IESO market rules*
$PD_BE_{k,h}^{i,t}$	*Energy Offer* submitted into the Pre-dispatch	*Energy offers* submitted in Pre-dispatch, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered price in each *price quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2.	9.3.1.2D	Same as *IESO market rules.*
$PD_BL_{k,h}^{i,t}$	*Energy* Bid submitted into the Pre-dispatch	Energy bids submitted in *pre-dispatch*, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered price in each	9.3.1.2D	Same as *IESO market rules.*

Key to the Table Below				
Variable used within Section 2	**Data Description**	**Description**	**Market Rules Reference**	**Relation to the corresponding variable description within the IESO Market Rules**
		price quantity pair where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2.		
$PD_DQSI_{k,h}^{i,t}$	*Pre-dispatch* quantity scheduled for injection at an *intertie metering point*	*Pre- dispatch* constrained quantity scheduled for injection by *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h'.	9.3.1.2C	Same as *IESO market rules*
$PD_DQSW_{k,h}^{i,t}$	*Pre-dispatch* quantity scheduled for withdrawal at an *intertie metering point*	*Pre- dispatch* constrained quantity scheduled for withdrawal by *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h'.	9.3.1.2C	Same as *IESO market rules*
$PD_ELMP_{h}^{m,t}$	*Pre-dispatch* constrained schedule price for an *intertie metering point* in the export zone	*Pre-dispatch* constrained schedule intertie price at the *delivery point* 'm ' of the sink for the export transaction during *metering interval* 't' of *settlement hour* 'h'.	9.3.1.2C	Same as *IESO market rules.*
$PD_EMP_{h}^{m,t}$	Pre-dispatch energy market price for Ontario	*Pre-dispatch* projected *energy market price* applicable to all *delivery points* 'm' in the Ontario zone in *metering interval* 't' of *settlement hour* 'h'.	9.3.1.2C	Same as *IESO market rules*
$PD_ILMP_{h}^{m,t}$	*Pre-dispatch* constrained schedule price for an *intertie metering point* in the import zone	*Pre-dispatch* constrained schedule intertie price at the *delivery point* 'm' of the source for the import transaction during *metering interval* 't' of *settlement hour* 'h'.	9.3.1.2C	Same as *IESO market rules.*

Key to the Table Below				
Variable used within Section 2	**Data Description**	**Description**	**Market Rules Reference**	**Relation to the corresponding variable description within the IESO Market Rules**
$PDF_{k,m,d}$	Peak Demand Factor	The Peak Demand Factor for Class A Market Participant or Distributor 'k' for month 'm' with effectiveness ratio 'd'.	N/A – subject to regulation by the *Ontario Energy Board*	N/A – See regulations.
$PDR_BE_{k,h}^{i,t}$	*Energy Offer* submitted into the *pre-dispatch of record*	EFFECTIVE OCTOBER 13, 2011, THIS VARIABLE IS NO LONGER USED IN THE CALCULATION OF ANY SETTLEMENT. *Energy offers* submitted into the *pre-dispatch of record,* represented as an n by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered price in each *price-quantity pair*, where *offered prices* are in column 1 and *offered quantities* are in column 2.	9.3.1.2B	Same as *IESO market rules*
$PDR_DQSI_{k,h}^{i,t}$	*Pre-dispatch of record* dispatch quantity scheduled for injection at an *intertie metering point*	EFFECTIVE OCTOBER 13, 2011, THIS VARIABLE IS NO LONGER USED IN THE CALCULATION OF ANY SETTLEMENT. *Pre-dispatch of record* constrained quantity scheduled for injection by *market participant* 'k' for an import transaction at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h'.	9.3.1.2A	Same as *IESO market rules*

Key to the Table Below				
Variable used within Section 2	**Data Description**	**Description**	**Market Rules Reference**	**Relation to the corresponding variable description within the IESO Market Rules**
$PDR_DQSI_{k,h}^{m,t}$	*Pre-dispatch of record* dispatch quantity scheduled for injection at a *delivery point*	EFFECTIVE OCTOBER 13, 2011, THIS VARIABLE IS NO LONGER USED IN THE CALCULATION OF ANY SETTLEMENT. *Pre-dispatch of record* constrained quantity scheduled for injection by *market participant* 'k' at *delivery point* 'm' during *metering interval* 't' of *settlement hour* 'h'.	9.3.1.2A	Same as *IESO market rules*
$PGS_{h,M}$	Allocated Quantity of Energy Withdrawn by OPG at Beck Pump Generating Station	Allocated quantity in MWh of *energy* withdrawn by OPG at Beck Pump Generating Station in *metering interval* 't' of *settlement hour* 'h' for month 'M'.		
$PROR_{r,h}^{m,t}$	5-minute Operating Reserve Price	*Market price* in $/MW of *class r reserve* in *metering interval* 't' of *settlement hour* 'h' at *RWM* 'm' or *intertie metering point* 'm'.	9.3.1.4	Same as *IESO market rules*.
$PST_{k,h}^{p,t}$	Steam turbine portion from Daily Generator Data	The percentage of the *pseudo-unit*'s schedule that relates to the steam turbine in association with *offer k* for *market participant* 'k' at *pseudo unit* 'p' during *metering interval* 't' of *settlement hour* 'h'.	7.2.2.2	Same as *IESO market rules*.
PTS-L	Provincial Transmission Service Line Connection Service Rate ($/KW)	Line Connection Transmission Tariff Service Rate in units of dollars per kilowatt.	N/A	Subject to the OEB "Ontario Transmission Rate Order".

Key to the Table Below				
Variable used within Section 2	**Data Description**	**Description**	**Market Rules Reference**	**Relation to the corresponding variable description within the IESO Market Rules**
PTS-N	Provincial Transmission Service Network Service Rate ($/KW)	Network Transmission Tariff Service Rate in units of dollars per kilowatt.	N/A	Subject to the OEB "Ontario Transmission Rate Order".
PTS-T	Provincial Transmission Service Transformation Connection Service Rate ($/KW)	Transformation Connection Service Transmission Tariff Rate in units of dollars per kilowatt.	N/A	Subject to the OEB "Ontario Transmission Rate Order".
$QTR_{k,h}^{i,j}$	Quantity of Transmission Rights Owned	Quantity of TRs in MW assigned to *market participant* 'k' for transmission from injection *TR zone* 'i' to withdrawal *TR zone* 'j'.	9.3.1.8 and 8.4.2	Same as *IESO market rules*.
$RAC^{m}{}_{k}$	Resource Available Capacity (MW)	The available capacity (in MW) of *capacity auction resource* at *delivery point* or *intertie metering point* 'm' for *capacity market participant* 'k' in the applicable *obligation period*, and is determined in accordance with the following: For *capacity dispatchable load resources* and *hourly demand response resources*: $RAC^{m}{}_{k} = MIN(DREBQ^{m}{}_{k,h}, (1.15 * CCO^{m}{}_{k,h}), CICAP^{m}{}_{k}, CARC_{k}{}^{m})$ Where:	9.3.1.10	Same as *IESO market rules*

Key to the Table Below				
Variable used within Section 2	**Data Description**	**Description**	**Market Rules Reference**	**Relation to the corresponding variable description within the IESO Market Rules**
		$CARC_k^m$ is only applicable to virtual *hourly demand response resources* For *capacity generation resources*, *system-backed capacity import resources, generator-backed capacity import resources and capacity storage resources*: $RAC^m_k = MIN(CAEO^m_{h,k}, (1.15* CCO^m_{k,h}), CICAP^m_k)$		
RPP_l	Regulated Price Plan	A fixed *energy* rate for all *metering intervals* based on consumption level l.	N/A – subject to regulation by the *Ontario Energy Board*	N/A – See regulations.
$RPPVA_k$	Total volume of electricity distributed to prescribed Class B consumers	The total volume of electricity distributed to Class B consumers whose rates are determined under subsection 79.16 (1) of the *Ontario Energy Board Act, 1998* during the month by licensed distributor 'k'.	N/A	N/A – See regulations.
RQ	Reallocate Quantity	A quantity derived from a *physical bilateral contract quantity* ($BCQ_{k,b,h}^{m,t}$ or $BCQ_{s,k,h}^{m,t}$) in order to reallocate a component of *hourly uplift* from the *buying market participant* to the *selling market participant* in direct	N/A	See hourly uplift charge types in Section 2.2

Key to the Table Below				
Variable used within Section 2	**Data Description**	**Description**	**Market Rules Reference**	**Relation to the corresponding variable description within the IESO Market Rules**
		proportion to the size of the *physical bilateral contract.*		
$SQEI_{k,h}^{i,t}$	Scheduled Quantity of Energy Injected at an *intertie metering point*	Scheduled quantity in MWh of *energy* injected by *market participant* 'k' at *intertie metering point* 'i' for each *metering interval* 't' in *settlement hour* 'h'.	9.3.1.9	This variable is a sub-set of variable AQEI described in Section 3.1.9 of Chapter 9 of the *market rules*, specifically referring to those quantities derived from *interchange schedule data*.
$SQEW_{k,h}^{i,t}$	Scheduled Quantity of Energy Withdrawn at an *intertie metering point*	Scheduled quantity in MWh of *energy* withdrawn by *market participant* 'k' at *intertie metering point* 'i' for each *metering interval* 't' in *settlement hour* 'h'.	9.3.1.9	This variable is a subset of variable AQEW described in Section 3.1.9 of Chapter 9 of the *market rules*, specifically referring to those quantities derived from *interchange schedule data*.
$SQROR_{r,k,h}^{m,t}$	Scheduled Quantity of class r Operating Reserve	Market Schedule quantity in MW of *class r reserve* for *market participant* 'k' in *metering interval* 't' of *settlement hour* 'h' at *RWM* 'm'.	9.3.1.4	Same as *IESO market rules*.
$TAOR_{k,h}^{m,t}$	Total Accessible Operating Reserve	Quantity of operating reserve available from *market participant* 'k' in *metering interval* 't' of *settlement hour* 'h' at *RWM* 'm'.	9.3.4.2	Same as *IESO market rules*.

Key to the Table Below				
Variable used within Section 2	**Data Description**	**Description**	**Market Rules Reference**	**Relation to the corresponding variable description within the IESO Market Rules**
$TCD_{k,h}{}^{m}$	Transformation Connection Demand (KW)	Billing Demand for Transformation Connection Transmission Service (KW) for *transmission customer* 'k' at transmission delivery point m during *settlement hour* 'h' in which $TCD_{k,h}{}^{m}$ denotes the non-coincident peak demand for the month.	N/A	Subject to the OEB "Ontario Transmission Rate Order".
$TD_{k,h,c}$	Total Market Settlement Amount	Total *settlement amount* (dollars) for the market used in *hourly uplift* and calculations for various other non-hourly *settlement amounts* for *market participant* 'k' or *transmission customer* 'k' during *settlement hour* 'h' with respect to *charge type* 'c'.	N/A	This is purely a notational term is used within the documentation to describe the aggregation of various *settlement amounts.* A summation across *charge type* 'c' denotes an aggregation of all *settlement amounts* for that *charge type* for the time period concerned. e.g.: $\sum_c{}^{T}$ indicates a summation of all *settlement amounts* for *charge type* 'c' during all *metering intervals* 'T'.
TLQ	Threshold Load Quantity	A threshold (kWh) with respect to monthly consumption of regulated customers, set by the *OEB.*	N/A – subject to regulation by the *Ontario Energy Board.*	N/A – See regulations.
TP_c	Tariff price	A stipulated rate ($/MWh, $/KW) used in the calculation of a specific *charge type* 'c'.	N/A	This is purely a notational term is used within the documentation to describe the unique per MW or per MWh rate applied to specific

Key to the Table Below				
Variable used within Section 2	**Data Description**	**Description**	**Market Rules Reference**	**Relation to the corresponding variable description within the IESO Market Rules**
				quantities in order to calculate various *settlement amounts*.
TRMP	TR Market Clearing Price	The price of each *transmission right* in a single round of a *TR auction*.	8.4.15	Same as *IESO market rules*.
TRCAD	TR Clearing Account Disbursements	The total dollar value of all disbursements from the *TR clearing account* authorized by the *IESO Board* in the current *energy market billing period*.	9.4.7.2	Same as *IESO market rules.*
TRCAD_E	TR Clearing Account Disbursements for Exporters	The proportion of the total dollar value of all disbursements from the *TR clearing account* authorized by the *IESO Board* in the current *energy market billing period* allocated to exporters.	9.4.7.2	Same as *IESO market rules.*
TRCAD_L	TR Clearing Account Disbursements for Loads	The proportion of the total dollar value of all disbursements from the *TR clearing account* authorized by the *IESO Board* in the current *energy market billing period* allocated to loads.	9.4.7.2	Same as *IESO market rules.*
TRCAR	TR Shortfall Recovery Amount	The total dollar value of TR shortfall recovery from the *TR clearing account* authorized by the *IESO Board* in the current *energy market billing period*.	9.4.7.2	Same as *IESO market rules.*

Key to the Table Below				
Variable used within Section 2	**Data Description**	**Description**	**Market Rules Reference**	**Relation to the corresponding variable description within the IESO Market Rules**
U_k	Energy Storage Facility Injection	The total volume of *energy* (MWh) conveyed back into the *IESO-controlled grid* during the month by energy storage facilities associated with Class B *market participant* 'k' and the total volume of *energy* (MWh) conveyed back into the *distribution system* during the month by energy storage facilities that are Class B consumers of *distributor* 'k'.	N/A	N/A – See regulations.
$X_h^{\mathrm{m,t}}$	Settlement Floor Price for exports	A *settlement* floor price for *energy* applicable to *intertie metering point* 'm' *metering interval* 't' in *settlement hour* 'h' as set in the applicable *market manual*. The need for a *settlement* floor price other than *MMCP* shall remain in effect only until floor prices for *energy offers* from *registered market participants* that are *variable generators* or nuclear *generators* go into effect.	9.3.1.3	Same as *IESO market rules*

2.2 Charge Types and Equations

The following table contains the *IESO charge types* and equations that are part of an active *IESO-administered market*.

Notice to Electricity Storage Participants – As of January 2021, substantial amendments to the *market rules* came into effect allowing for increased participation of *electricity storage participants* and *electricity storage facilities* in the *IESO-administered markets* and on the *IESO-controlled grid.* However, the *IESO* does not anticipate updating the *charge types* and equations set out in this Section 2.2, the variable descriptions set out in Section 2.1 above, or any other potentially affected parts of this document to reflect those *market rule* amendments until the *IESO*'s commercial reconciliation tools shall have been updated. Therefore, until such time, settlement programs, variable descriptions, *charge types* and equations will be applied to *electricity storage participants* and their *electricity storage facilities* as follows:

(i) the relevant provisions of Market Manual 5: Settlements, Part 5.5: Physical Markets Settlement Statements and all other relevant *market manuals* have been updated to reflect the aforementioned *market rule* amendments with respect to settlements of transactions and other circumstances relating to *electricity storage participants* and *electricity storage facilities*, and;

(ii) based on these updated provisions, the variable descriptions, *charge types* and equations set out in this document will, as appropriate, be applied to the settlement of all relevant transactions and other circumstances, subject to the making of any alterations to such variable descriptions, *charge types* and equations as may be necessary to properly apply them in respect of each such transaction or other circumstance.

Key to the Table Below	
Charge Type Number	The designation number for each *charge type* enumerated below – which correspond to the *charge type* numbers used on *settlement statements* and *invoices.*
Charge Type Name	The name of the *charge type.*
Settlement Amount Acronym	The abbreviated name of the variable used to describe the *settlement amount* within the *IESO market rules*.

Key to the Table Below	
Market Rules Reference	The relevant reference to the variable in question within the *IESO market rules*. The format for each reference is: [Chapter] [Section number] For example: "Chapter 9 Section 3.1.6" would appear as: 9.3.1.6
Equation	The equation used by the *IESO settlements process* to calculate the *settlement amount* related to each *charge type*.
Settlement Resolution	The level of granularity by which the *IESO settlements process* calculates the *settlement amount* (for which the *charge type* is related), and provides the supporting data in the settlement data file. Where: • "Interval" means that the calculations are performed on the basis of each relevant, 5-minute *metering interval*; • "Hourly" means that the calculations are performed on the basis of each *settlement hour*; • "Daily" means that the calculations are performed on the basis of each calendar day; • "Monthly" means that the calculations are performed on the basis of a calendar month (equivalent to a real-time market *billing period*); • "Quarterly" means that the calculations are performed on the basis of 3 month intervals; • "Yearly" means that the calculations are performed on the basis of a calendar year.

Key to the Table Below	
Cashflow	This column indicates whether or not the *settlement amount* (for which the *charge type* is related) is: • "Due *IESO*" – which means, owed to the *IESO* by the *market participant*; *** or • "Due MP" – which means, owed to the *market participant* by the *IESO*; *** or • "Either Way" – which indicates that the *settlement amount* in question could be either owed to the *IESO* by the *market participant* or owed to the *market participant* by the *IESO* in any given time period (according to the applicable "settlements resolution"). *****NOTE in cases where a Cashflow is designated as "Due *IESO*" or "Due MP" this should be read in the context of its intended use in the normal course of *settlements*. However, such cashflows can always be REVERSED in situations where an adjustment is applied to a *market participant*, or the application of a per-unit charge in order to offset an adjustment to another *market participant*.**
HST Tax Treatment within Ontario	• This column indicates the percentage levy as per the Harmonized Sales Tax (HST). • Zone used for Tax Basis is (ONZN) for Ontario. • The applicable Zone ID may be found in column 7 of the applicable settlement statement detail record (see also, the Technical Interface Document entitled, "Detail Field Description"). • A complete list of Zones may be found in the Technical Interface Document entitled, "Standing Data".
HST Tax Treatment for U.S., Manitoba and Quebec Generation	• This column indicates the percentage levy as per the Harmonized Sales Tax (HST). • Zones used for Tax Basis are (NYSI) for US Generation, (MBSI) for Manitoba Generation and (PQSI) for Quebec Generation. • The applicable Zone ID may be found in column 7 of the applicable settlement statement detail record (see also, the Technical Interface Document entitled, "Detail Field Description"). • A complete list of Zones may be found in the Technical Interface Document entitled, "Standing Data".
HST Tax Treatment for US Load	• This column indicates the percentage levy as per the Harmonized Sales Tax (HST). • Zone used for Tax Basis is (NYSI) for US Load. • The applicable Zone ID may be found in column 7 of the applicable settlement statement detail record (see also, the Technical Interface Document entitled, "Detail Field Description"). • A complete list of Zones may be found in the Technical Interface Document entitled, "Standing Data".

Key to the Table Below	
HST Tax Treatment for Manitoba and Quebec Load	• This column indicates the percentage levy as per the Harmonized Sales Tax (HST). • Zones used for Tax Basis are (MBSI) for Manitoba Load and (PQSI) for Quebec Load. • The applicable Zone ID may be found in column 7 of the applicable settlement statement detail record (see also, the Technical Interface Document entitled, "Detail Field Description"). • A complete list of Zones may be found in the Technical Interface Document entitled, "Standing Data".
Effective Start Trading Day	• This column indicates the effective start *trading day* of the *charge type*.
Effective End Trading Day	• This column indicates the effective end *trading day* of the *charge type*.
Comments	This column notes any *charge types* that are governed by various documentation other than the *IESO market rules* and additional details for "Effective Start Trading Day" and "Effective End Trading Day" columns, where applicable.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
	Financial Market Charge Types												
52	Transmission Rights Auction Settlement Debit	N/A	8.4.17	$QTR_{k,h}^{i,j} \times TRMP$	Daily	Due *IESO*	Exempt	Exempt	Exempt	Exempt			
	Physical Market Charge Types												
100	Net Energy Market Settlement for Generators and Dispatchable Load	$NEMSC_{k,h}$	9.3.3.2	For *dispatchable facilities* or an *intertie metering point* associated with: i) An injecting *boundary entity*; ii) A withdrawing *boundary entity* where the associated *intertie congestion price* is less than zero; iii) A withdrawing *boundary entity* conducting a wheeling through transaction that is linked as per Chapter 7, section 3.5.82 of the *market rules* $\Sigma_{t,M,}(EMP_h^{m,t} \times ((AQEI_{k,h}^{m,t} + SQEI_h^i - AQEW_{k,h}^{m,t} - SQEW_h^i)$	Interval	Either Way	13	13	0	13	May 1, 2002	April 30, 2023	

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				$+\Sigma_{s,b}(\mathrm{BCQ}_{s,k,h}{}^{m,t}-\mathrm{BCQ}_{k,b,h}{}^{m,t})))$ For an *intertie metering point* associated with a withdrawing *boundary entity* where that *intertie congestion price* is not less than zero: $\Sigma_{t,M,}((\mathrm{MAX}(X_h{}^{m,t},\mathrm{EMP}_h{}^{m,t}) \times \mathrm{AQEI}_{k,h}{}^{m,t})$									
101	Net Energy Market Settlement for Non-dispatchable Load	$\mathrm{NEMSC}_{k,h}$	9.3	$\mathrm{HOEP}_h \times \Sigma_{t,m}(\mathrm{AQEI}_{k,h}{}^{m,t} - \mathrm{AQEW}_{k,h}{}^{m,t} + \Sigma_s \mathrm{BCQ}_{s,k,h}{}^{m,t} - \Sigma_{n,b,t}(\mathrm{EMP}_h{}^{m,t}\mathrm{BCQ}_{k,b,h}{}^{n,t}$	Hourly	Either Way	13	N/A	N/A	N/A	May 1, 2002	April 30, 2023	
102	TR Clearing Account Credit	TRCAC_k	9.4.7.2	**For loads:** $\mathrm{TRCAC}_k = \mathrm{TRCAD}_L \times \sum_H{}^{M,T} [(\mathrm{AQEW}_{k,h}{}^{m,t})/\sum_{K,H}{}^{M,T}(\mathrm{AQEW}_{k,h}{}^{m,t})]$ **For exporters:** $\mathrm{TRCAC}_k = \mathrm{TRCAD}_E \times \sum_H{}^{I,T} [(\mathrm{SQEW}_{k,h}{}^{i,t})/\sum_{K,H}{}^{I,T}(\mathrm{SQEW}_{k,h}{}^{i,t})]$ **Where** $\mathrm{TRCAD}_L = (\sum_K \mathrm{TD}_C/\sum_K \mathrm{TD}_{C,C1}) \times \mathrm{TRCAD}$ $\mathrm{TRCAD}_E = (\sum_K \mathrm{TD}_{C1}/\sum_K \mathrm{TD}_{C,C1}) \times \mathrm{TRCAD}$ Where 'C' is the set of all *monthly service charge types c as follows: 650,651,652.*	Monthly (when applicable)	Due MP	13	N/A	0	13			The *billing period* is defined in Market Manual 5.5: Settlements Part 5.5: Physical Markets Settlement Statements, section 1.6.27

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				Where 'CT' is the set of all *monthly export transmission charge types c as follows:653.* Where 'H' is the set of all s*ettlement hours* 'h' in the *billing periods* immediately preceding the current *billing period*, as determined by *IESO Board.* Where 'T' is the set of all *metering intervals* 't' in the set of all *settlement hours* 'H'. Where 'M' is the set of all *delivery points* 'm', excluding any *intertie metering points*. Where 'I' is the set of all *intertie metering points* 'i'. Where 'K' is the set of all *market participants* 'k'.									
103	Transmission Charge Reduction Fund	$TCRF_h$	9.3.6.2 and 8.4.18	$(\Sigma_{t,m}(EMP_h^{m,t} - EMP_h^{REF,t}) \times \Sigma_k(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t} - AQEI_{k,h}^{m,t} - SQEI_{k,h}^{i,t}) - \Sigma_k TRSC_{k,h}$	Hourly	Accumulates in the *TR Clearing Account*	N/A	N/A	N/A	N/A			See *IESO market rules*, Chapter 8 Section 4.18 for further details.
104	Transmission Rights Settlement Credit	$TRSC_{k,h}$	9.3.6.1	$MAX((0), (\Sigma_{j,i}1/12 \times QTR_{k,h}^{i,j} \times \Sigma_t(EMP_h^{j,t} - EMP_h^{i,t}))$	Hourly	Due MP	0	0	0	0			
105	Congestion Management Settlement Credit for Energy	$CMSC_{k,h}$	9.3.5.2 to 9.3.5.7	$OP(EMP_h^{m,t}, MQSI_{k,h}^{m,t}, BE) - MAX(OP(EMP_h^{m,t}, DQSI_{k,h}^{m,t}, BE), OP(EMP_h^{m,t}, AQEI_{k,h}^{m,t}, BE))$ Subject to the mathematical sign of (DQSI-MQSI) being equal to the mathematical sign of (AQEI-MQSI).	Interval	Either Way	13	13	13	13			This *charge type* holds the *market participant* to the expected profits implied by the *market schedule* derived on *dispatch data* provided by that

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				$AQEI_{k,h}^{m,t}$ and $EMP_h^{m,t}$ may be substituted with $SQEI_{k,h}^{i,t}$ and $EMP_h^{i,t}$ respectively, where the application of this equation pertains to *intertie metering point* 'i'. or $-1OP(EMP_h^{m,t}, MQSW_{k,h}^{m,t}, BL) - MA(-1OP(EMP_h^{m,t}, DQSW_{k,h}^{m,t}, BL), -1OP(EMP_h^{m,t}, AQEW_{k,h}^{m,t}, BL))$ Subject to the mathematical sign of (DQSW-MQSW) being equal to the mathematical sign of (AQEW-MQSW). $AQEW_{k,h}^{m,t}$ and $EMP_h^{m,t}$ may be substituted with $SQEW_{k,h}^{i,t}$ and $EMP_h^{i,t}$ respectively, where the application of this equation pertains to *intertie metering point* 'i'. or For *variable generators* that are registered *market participants* whose *registered facility* is operating under a release notification for any given *dispatch interval*, and the *facility*'s market schedule quantity is less than the corresponding quantity in the									*market participant*. Offer prices in matrix 'BE' may be revised down to a lower limit as described in 9.3.5.6. See also: description of variable 'BE' in Section 2.2. The bid prices in the matrix BL may be revised as described in Market Manual 5: Settlements Part 5.5: Physical Markets Settlement Statements, section 1.6.8.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				constrained schedule for the same dispatch interval as a result of the *market participant*'s offers being partially or fully uneconomic: $\mathrm{OPE}(\mathrm{EMP}_h^{m,t}, \mathrm{MQSI}_{k,h}^{m,t}, \mathrm{BE}) - \mathrm{OP}(\mathrm{EMP}_h^{m,t}, \mathrm{AQEI}_{k,h}^{m,t}, \mathrm{BE})$ See 9.3.5.2 for the definition of the Operating Profit (OP) function referenced above.									
106	Congestion Management Settlement Credit for 10 Minute Spinning Reserve	$\mathrm{CMSC}_{r,k,h}$	9.3.5.2	$\mathrm{OP}(\mathrm{PROR}_{r,h}^{m,t}, \mathrm{SQROR}_{r,k,h}^{m,t}, \mathrm{BR}_r) - \mathrm{MAX}(\mathrm{OP}(\mathrm{PROR}_{r,h}^{m,t}, \mathrm{DQSR}_{r,k,h}^{m,t}, \mathrm{BR}$ $\mathrm{OP}(\mathrm{PROR}_{r,h}^{m,t}, \mathrm{AQOR}_{r,k,h}^{m,t}, \mathrm{BR}_r))$ See 9.3.5.2 for the definition of the Operating Profit (OP) function referenced above.	Interval	Either Way	13	N/A	N/A	N/A			This charge type holds the market participant to the expected profits implied by the market schedule derived on dispatch data provided by that market participant.
107	Congestion Management Settlement Credit for 10 Minute Non-spinning Reserve	$\mathrm{CMSC}_{r,k,h}$	9.3.5.2	$\mathrm{OP}(\mathrm{PROR}_{r,h}^{m,t}, \mathrm{SQROR}_{r,k,h}^{m,t}, \mathrm{BR}_r) - \mathrm{MAX}(\mathrm{OP}(\mathrm{PROR}_{r,h}^{m,t}, \mathrm{DQSR}_{r,k,h}^{m,t}, \mathrm{BR}$ $\mathrm{OP}(\mathrm{PROR}_{r,h}^{m,t}, \mathrm{AQOR}_{r,k,h}^{m,t}, \mathrm{BR}_r))$ See 9.3.5.2 for the definition of the Operating Profit (OP) function referenced above.	Interval	Either Way	13	N/A	N/A	N/A			This charge type holds the market participant to the expected profits implied by the market schedule derived on dispatch data provided by that

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
													market participant.
108	Congestion Management Settlement Credit for 30 Minute Operating Reserve	$CMSC_{r,k,h}$	9.3.5.2	$OP(PROR_{r,h}^{m,t}, SQROR_{r,k,h}^{m,t}, BR_r)$ – $MAX(OP(PROR_{r,h}^{m,t}, DQSR_{r,k,h}^{m,t}, B$ $OP(PROR_{r,h}^{m,t}, AQOR_{r,k,h}^{m,t}, BR_r))$ See 9.3.5.2 for the definition of the Operating Profit (OP) function referenced above.	Interval	Either way	13	N/A	N/A	N/A			This *charge type* holds *the market participant* to the expected profits implied by the *market schedule* derived on *dispatch data* provided by that *market participant*.
111	Northern Pulp and Paper Mill Electricity Transition Program Settlement Amount	N/A	N/A	$= \sum_{M\ H}{}^{T}(AQEW_{mh}{}^{t}) \times (Tprate)$ Where: Tprate is the transition program rate 'M' is the set of all *delivery points* 'm' for all *market participant*-eligible *facilities*. 'H' is the set of all *settlement hours* 'h' in the settlement period. 'T' is the set of all *metering intervals* 't' in the set of all *settlement hours* 5 H'.	Quarterly	Due MP	13	N/A	N/A	N/A			Eligibility, rates, and other implementation details subject to Ministry of Natural Resources specifications. This program ends on September 30, 2010.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				'AQEW' is limited to a maximum of 1,000,000 MWh annually per eligible *market participant*.									
112	Ontario Power Generation Rebate	N/A	N/A	**** CALCULATIONS FOR *CHARGE TYPE* 112 END April 30, 2009 **** $= TD_{162} \times [(AQEW_{k,h}{}^{t})/\sum_{K,H}{}^{T}(AQEW_{k,h}{}^{t})]$ Where: 'K' is the set of all Ontario *market participants* 'k' 'H' is the set of all *settlement hours* 'h' in the applicable quarter. 'T' is the set of all *metering intervals* 't' in the set of all *settlement hours* 'H'.	May 1, 2006 to April 30, 2009	Due MP	13	N/A	N/A	N/A			The Ontario Power Generation Rebate payments will be based on the allocated quantity of *energy* withdrawn for the applicable quarter.
113	Additional Compensation for Administrative Pricing Credit	N/A	7.8.4A.16 or 7.8.4A.10 or 7.13.6.2	Manual Entry as per 7.8.4A.16, or 7.8.4A.10, or 7.13.6.2.	Monthly	Due MP	13	13	0	13			This charge will still be used for market suspension events
114	Outage Cancellation/Deferral Settlement Credit.	N/A	5.6.7.4	Manual Entry as per 5.6.7.4.	Monthly	Due MP	13	N/A	N/A	N/A			

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
115	Unrecoverable Testing Costs Credit	N/A	9.4.8.1.1 and4.5.3.4	Manual Entry as per 4.5.3.4.	Monthly	Due MP	13	13	13	13			
116	Tieline Maintenance Reliability Credit	N/A	9.4.8.1.2 and 5.5.3.4	Manual Entry as per 5.5.3.4.	Monthly	Due MP	13	13	13	13			
118	Emergency Energy Rebate	N/A	9.4.8.2 and 5.4.4A.1	$= \sum_{H,c}{}^{M,T} TD_c \times [(AQEW_{k,h}{}^{m,t} + SQEW_{k,h}{}^{i,t}) / \sum_{k,H}{}^{M,T} (AQEW_{k,h}{}^{m,t} + SQEW_{k,h}{}^{i,t})]$ Where ‘H’ is the set of all *settlement hours* ‘h’ in the month. Where ‘T’ is the set of *all metering intervals* ‘t’ in the set of all *settlement hours* ‘H’.	Monthly	Due MP	13	N/A	0	13			
119	Station Service Reimbursement Credit	N/A	9.4.8.1.6 and 9.2.1A.9 - 2.1A14	$= \{TD_{C,k,h}{}^{m,T} \times [\sum^{T2} (AQEW_{k,h}{}^{M,t}) / \sum_{K,h}{}^{T} (AQEW_{k,h}{}^{m,t} + SQEW_{k,h}{}^{i,t})]\} + \{TD_{C2,k,H}{}^{m,T} \times [\sum_{H2}{}^{T2} (AQEW_{k,h}{}^{M,t}) / \sum_{K,H}{}^{T} (AQEW_{k,h}{}^{m,t} + SQEW_{k,h}{}^{i,t})]\} + \{TD_{C3,k,H}{}^{m,T} \times [\sum_{H4}{}^{T2} (AQEW_{k,h}{}^{M,t}) / \sum_{K,H3}{}^{T} (AQEW_{k,h}{}^{m,t} + SQEW_{k,h}{}^{i,t})]\}$ Where: ‘T’ is the set of all *metering intervals* in *settlement hour* ‘h’.	Monthly	Due MP	13	N/A	N/A	N/A	June 1, 2002	April 30, 2023	

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				'M' is the eligible generation station service delivery point 'm' of market participant 'k' 'C' is the set of the following hourly uplift *charge type* c as follows: 150, 155, 250, 252, 254, 451 'T2' is the set of all *metering intervals* in *settlement hour* 'h' where the eligible *generation facility* was a net injector of *energy* into the *IESO-controlled grid*. 'K' is the set of all *market participants* 'C2' is the set of the following non-hourly monthly *charge type* 'c' as follows: 163,164,165,166,167,168,169,183, 184,450,452,454,460,550,1188, 1650 'C3' is the set of the following daily *charge type* 'c' as follows: 1550, 1560 'H' is the set of all *settlement hours* 'h' in the *billing period*									

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				'H2' is the set of all *settlement hours* 'h' in the *billing period* where the eligible *generation facility* was a net injector of *energy* into the *IESO-controlled grid*. 'H3' is the set of all *settlement hours* 'h' in the day 'H4' is the set of all *settlement hours* 'h' in the day where the eligible *generation facility* was a net injector of *energy* into the *IESO-controlled grid*.									
119	Station Service Reimbursement Credit	N/A	9.4.8.1.6 and 9.2.1A.9 - 2.1A14	$= \{TD_{C,k,h}^{m,T} \times [\sum^{T2} (AQEW_{k,h}^{M,t}) / \sum_{K,h}^{T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t})]\} + \{TD_{C2,k,H}^{m,T} \times [\sum_{H2}^{T2} (AQEW_{k,h}^{M,t}) / \sum_{K,H}^{T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t})]\} + \{TD_{C3,k,H}^{m,T} \times [\sum_{H4}^{T2} (AQEW_{k,h}^{M,t}) / \sum_{K,H3}^{T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t})]\}$ Where: 'T' is the set of all *metering intervals* in *settlement hour* 'h'. 'M' is the eligible generation station service delivery point 'm' of market participant 'k'	Monthly	Due MP	13	N/A	N/A	N/A	May 1, 2023		

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				'C' is the set of the following hourly uplift *charge type* c as follows: 150, 155, 186, 250, 252, 254, 451 'T2' is the set of all *metering intervals* in *settlement hour* 'h' where the eligible *generation facility* was a net injector of *energy* into the *IESO-controlled grid*. 'K' is the set of all *market participants* 'C2' is the set of the following non-hourly monthly *charge type* 'c' as follows: 102, 163,164,165,166,167,168,170, 183, 184,450,452,454,460,550,1188, 1650, 9920 'C3' is the set of the following daily *charge type* 'c' as follows: 1550, 1560 'H' is the set of all *settlement hours* 'h' in the *billing period* 'H2' is the set of all *settlement hours* 'h' in the *billing period* where the eligible *generation facility* was a net									

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				injector of *energy* into the *IESO-controlled grid*. 'H3' is the set of all *settlement hours* 'h' in the day 'H4' is the set of all *settlement hours* 'h' in the day where the eligible *generation facility* was a net injector of *energy* into the *IESO-controlled grid*.									
120	Local Market Power Debit	N/A	9.4.8.2.2 and Ch. 7, Appendix 7.6		Monthly	Due *IESO*	13	13	0	13			
121	Northern Industrial Electricity Rate Program Settlement Amount	N/A	N/A	$= \sum_{M\,H}{}^{T}(\mathrm{AQEW_{mh}}^{t}) \times (\mathrm{Rate})$ Where: Rate is the program rate 'M' is the set of all *delivery points* 'm' for all *market participant*-eligible *facilities*. 'H' is the set of all *settlement hours* 'h' in the settlement period. 'T' is the set of all *metering intervals* 't' in the set of all *settlement hours* 'H'.	Quarterly	Due MP	0	N/A	N/A	N/A	July 31, 2011	April 30, 2022	Eligibility, rates, and other implementation details subject to Ministry of Northern Development, Mines, Natural Resources and Forestry specifications.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
121	Northern Energy Advantage Program Settlement Amount	N/A	N/A	$= \sum_{M\,H}{}^{T}(\mathrm{AQEW_{mh}}{}^{t}) \times (\mathrm{Rate})$ Where: Rate is the program rate 'M' is the set of all *delivery points* 'm' for all *market participant*-eligible *facilities*. 'H' is the set of all *settlement hours* 'h' in the settlement period. 'T' is the set of all *metering intervals* 't' in the set of all *settlement hours* 'H'.	Quarterly	Due MP	0	N/A	N/A	N/A	July 31, 2022		Eligibility, rates, and other implementation details subject to Ministry of Northern Development, Mines, Natural Resources and Forestry specifications.
122	Ramp Down Settlement Amount	$RDSA_{k,h}$	9.3.5A.1	Let 'BE' be a matrix of n *price-quantity pairs* offered by *market participant* 'k' to supply *energy* during the *settlement hour* immediately before the hour in which ramp-down begins, adjusted by a ramp-down factor (RDF) as specified in the applicable *market manual*. Let OP(P,Q,B) be a function of Price (P), Quantity (Q) and an n × 2 matrix (B) of offered *price-quantity pairs*: $\mathrm{OP(P,Q,B)} = \mathrm{P} \cdot \mathrm{Q} - \sum_{i=1}^{S*} P_i \cdot (Q_i - Q_{\mathrm{i\text{-}1}}) - (Q - Q_{\mathrm{s*}}) \cdot P_{\mathrm{s*}+1}$	Interval	Either Way	13	N/A	N/A	N/A			The RDF is defined in Market Manual 5: Settlements Part 5.5: Physical Markets Settlement Statements, section 1.6.31.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				Where: s* is the highest indexed row of BE such that $Q_{s^*} \leq Q \leq Q_n$ and where, $Q_0 = 0$ Using the terms below, let $RDC_{k,h}^{m,t}$ be expressed as follows: $RDC_{k,h}^{m,t} = MAX[0, [OP(EMP_h^{m,t}, MQSI_{k,h}^{m,t}, BE) – MAX(OP(EMP_h^{m,t}, DQSI_{k,h}^{m,t}, BE), OP(EMP_h^{m,t}, AQEI_{k,h}^{m,t}, BE))]]$ $RDSA_{k,h}^{m,t} = MIN(-1 \times RDCB_{k,h}^{m,t}, RDC_{k,h}^{m,t})$									
123	MACD Enforcement Activity Amount	N/A	N/A	Manual entry based on the values submitted by MACD	Monthly	Due MP	13	N/A	N/A	N/A			
124	SEAL Congestion Management Settlement Credit Amount	N/A	N/A	Manual entry based on the values submitted by MACD	Monthly	Due MP	13	13	13	13			
130	Intertie Offer Guarantee Settlement Credit – Energy	$IOG_{k,h}$ and $IOG_{k,h}OFF$	9.3.8A.1 9.3.8A.3 and 7.3.5.8.1	****CALCULATIONS FOR *CHARGE TYPE* 130 END OCTOBER 12, 2011. *CHARGE TYPE* 130 REPLACED BY**	Hourly (the IOG Offset is debited)	Either Way	N/A	13	13	13			Compensation for cumulative, hourly financial losses as implied by the *market schedule* for Imports of

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				***CHARGE TYPE* 1131 EFFECTIVE OCTOBER 13, 2011.** The Intertie Offer Guarantee *settlement amount* is derived from an hourly *Energy* Import sub component ($EIM_{k,h}$) as follows: $\sum_I(-1)MIN[0,\sum^T OP(EMP_h^{i,t}, MQSI_{k,h}^{i,t}, BE)]$ See 9.3.8A.2 for the definition of the Operating Profit (OP) function referenced above. Where 'I' is the set of relevant *intertie metering points* 'i'. Where 'T' is the set of all *metering intervals* 't' during *settlement hour* 'h'. The IOG_OFFSET component of this *charge type* applied on a monthly basis and is calculated as follows: $= DA_IOG_{k,h} + EIM_{k,h} - \sum^I(-1) * MIN[0,\sum^T OP(EMP_h^{i,t}, QSI\{adj\}_{k,h}^{i,t}, BE_{k,h}^{i,t} \text{or } PDR_BE_{k,h}^{i,t}) + \sum^T QSI\{adj\} \sum^T MI_{k,h}^{t}[n,1] * OPE'_{k,h}{}^{i}]$									*energy* at an *intertie metering point.* This amount is reduced by the IOG Offset when the import is part of an implied "wheeling through" transaction as described in Section 3.5.8.1 of Chapter 7.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				(See 9.3.8A.4 for the derivation of the variable $QSI\{adj\}_{k,h}^{i,t}$, $OPE'_{k,h}{}^{i}$ and the proper context of the matrix notation $MI_{k,h}{}^{t}[n,1]$used above).									
133	Generation Cost Guarantee Payment	N/A	9.4.7B	Dispatchable *delivery points:* $MAX[0, (CGC + RT_COST - \sum^{T} EMP_{h}^{m,t} \times AQEI\{limited\}_{k,h}^{m,t} - - \sum^{T} CMSC_REV_{k,h}^{m,t}]$ **Subject to:** $AQEI\{limited\}_{k,h}^{m,t} = MIN[AQEI_{k,h}^{m,t}$, *minimum loading point*] Where 'CGC' is a *Submitted Combined Guaranteed Costs* variable, assessed in accordance with the applicable *market manual* (see also Section 2.1 "Variable Description"). Where 'm' is *delivery point* 'm' at which the *generation unit* incurring the relevant costs is located. Where 'T' is a set of *metering intervals* 't' from a valid start time until the earlier of:	Hourly	MP	13	N/A	N/A	N/A			

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				- the end of minimum generation block run-time; or - the end of the unit's *minimum run-time.* Where $\text{AQEI}\{\text{limited}\}_{\text{k,h}}^{\text{m,t}}$ shall denote all allocated quantities in MWh of *energy* injected at *delivery point* 'm' irrespective of any submission of *physical allocation data* by *market participant* 'k' in metering interval 't' of *settlement* hour 'h', up to the *generation unit's minimum loading point.* Where RT_COST is fuel and O&M cost component related to operation of the *generation unit* at its *minimum loading point* during its *minimum generation block run-time* (these costs are calculated based on the *offer* price associated with real-time dispatch). $\text{RT_COST}_{\text{k}} = \Sigma^{T*}{}_{\boldsymbol{H1}}\text{COST}(\text{AQEI}\{\text{limited}\}_{\text{k,h}}^{\text{m,t}}, \text{BE})$ A. Where the COST function is defined as follows:									

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				$\mathrm{COST}(Q,B) = \sum_{i=1}^{s^*} P_i \cdot (Q_i - Q_{i-1})$ *where:* • B is the n × 2 matrix (B) of offered *price-quantity pairs* (P_i, Q_i) • s* is the highest indexed row of B such that $Q_{s^*-1} \leq Q \leq Q_{s^*}$ and where $Q_0 = 0$ B. Where 'H1' is the set of all settlement hours 'h' during the period from beginning of the *minimum generation block run-time* until the end of the calculated *minimum run time.* We consider that the *minimum generation block run-time* starts with the first hour after we add the submitted number of ramp intervals to the valid start-up hour. C. Where 'T*' is the set of *metering intervals* 't' in the set of all *settlement hours* 'H1'									

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				Where $CMSC_REV_{k,h}^{m,t}$ is any real-time $CMSC(TD_{k,h,105}^{m,t})$ payment associated with allocated quantities in MWh of *energy* injected at *delivery point* 'm' irrespective of any submission of *physical allocation data* by *market participant* 'k' in metering interval 't' of *settlement* hour 'h' up to the *generation unit's minimum loading point.* CMSC_REV is calculated using the following rules: (1) Real-time $CMSC(TD_{k,h,105}^{m,t})$ for the same interval is greater than zero. (2) If $MQSI_{k,h}^{m,t}$ and $\max(DQSI_{k,h}^{m,t}, AQEI_{k,h}^{m,t}) >= M$, then $CMSC_REV_{k,h}^{m,t} = 0$. (3) In the case of a *constrained-off event*: a. If $MQSI_{k,h}^{m,t} <$ MLP, then $CMSC_REV_{k,h}^{m,t} = TD_{k,h,105}^{m,t}$ b. If $MQSI_{k,h}^{m,t} >=$ MLP and $\max(DQSI_{k,h}^{m,t}, AQEI_{k,h}^{m,t}) <=$ MLP, then $CMSC_REV_{k,h}^{m,t} = OP(EMP_{h}^{m,t}, MLP, BE)$									

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				– OP(EMP,max(DQSI $_{k,h}^{m,t}$,AQEI $_{k,h}^{m,t}$),BE). (4) In the case of a *constrained-on event*: a. If MQSI $_{k,h}^{m,t}$ < MLP and min(DQSI $_{k,h}^{m,t}$,AQEI $_{k,h}^{m,t}$) < MLP, then CMSC_REV $_{k,h}^{m,t}$ = TD $_{k,h,105}^{m,t}$ b. If MQSI $_{k,h}^{m,t}$ <= MLP and min(DQSI $_{k,h}^{m,t}$, AQEI $_{k,h}^{m,t}$) >=MLP, then CMSC_REV $_{k,h}^{m,t}$ = OP(EMP $_{h}^{m,t}$,MQSI $_{k,h}^{m,t}$,BE) – OP(EMP $_{h}^{m,t}$,MLP,BE) (See applicable *market manual*)									
134	Demand Response Credit	N/A	9.4.7C 9.4.7F	Manual Entry for TDRP (Refer to "Market Manual 5: Settlements, Part 5.10: Transitional Demand Response Program". Manual Entry for ELRP (Refer to "Market Manual 10: Emergency Load Reduction Program (ELRP)".	Monthly	Either way	13	N/A	NA	N/A			TDRP and ELRP suspended by the *IESO*.
135	Real-time Import Failure Charge	RT_IFC$_{k,h}$	9.3.8C.3	$\sum^{I,T}(-1)$* MIN[MAX[0, (EMP $^{m\,t}$+ PB IM ^{t} PD EMP $^{m\,t}$)	Hourly	Due *IESO*	N/A	13	N/A	N/A			Subject to exemptions under the provisions of 9.3.8C.2.2.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				$RT_ISD_{k,h}^{i,t}$)] Where: 'I' is the set of all *intertie metering points* 'i'. 'T' is the set of 12 *metering intervals* 't' during *settlement hour* 'h'. $RT_ISD_{k,h}^{i,t} = MAX (PD_DQSI_{k,h}^{i,t} – DQSI_{k,h}^{i,t}, 0)$									
136	Real-time Export Failure Charge	$RT_EFC_{k,h}$	9.3.8C.5	$\sum^{I,T}(-1) * MIN[MAX[0, (PD_EMP_h^{m,t} – EMP_h^{m,t} – PB_EX_h^{t})* RT_ESD_{k,h}^{i,t}], (MAX(0, PD_EMP_h^{m,t})* RT_ESD_{k,h}^{i,t})]$ Where: 'I' is the set of all *intertie metering points* 'i' 'T' is the set of 12 *metering intervals* 't' during *settlement hour* 'h' $RT_ESD_{k,h}^{i,t} = MAX (PD_DQSW_{k,h}^{i,t} – DQSW_{k,h}^{i,t}, 0)$	Hourly	Due *IESO*	N/A	N/A	0	13			Subject to exemptions under the provisions of 9.3.8C.4.2.
137	Generation Cost Guarantee – Annual Carbon Charge Settlement Amount	N/A	9.4.7B.1.2 7.2.2B	Manual entry based on the calculations outlined in Market Manual 4: Market Operations Part 4.6: Real-Time Generation Cost	Monthly	Due MP	13	N/A	N/A	N/A	June 7, 2023		

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				Guarantee Program, section 5.4 Fuel Cost Recovery Methodology.									
140	Fixed Energy Rate Settlement Amount	N/A	N/A	**** *CHARGE TYPE* 140 REPLACED BY *CHARGE TYPE* 142 EFFECTIVE JANUARY 1, 2005 **** **NOTE:** The equations identified below apply to low volume and designated consumers (as defined in *Ontario Energy Board Act, 1998* and associated regulations) in the *IESO-administered market*. For *distributors, charge type* 140 is applied once a month based on the values submitted by the *distributor* on IMO_FORM_1562 (monthly adjustment) and IMO_FORM_1505 (May-Nov 2002 refund). For *IESO's* low volume and designated customers a fixed rate adjustment with a rate of 5.5 cents per kWh is applied on an interval basis using the equation below. A manual adjustment is applied at the end of the month to apply a rate of 4.7 cents per kWh for *energy* withdrawn up to 750 kWhs. **Fixed Energy Rate Settlement Amount (dispatchable locations):** **Where net uncovered consumption > 0:** $\Sigma_{T,m}(\mathrm{EMP}_h^{\mathrm{m,t}} - \mathrm{FP}_h^{m}) \times (\mathrm{AQEW}_{\mathrm{k,h}}^{\mathrm{m,t}} - \mathrm{AQEI}_{\mathrm{k,h}}^{\mathrm{m,t}} - \Sigma_s \mathrm{BCQ}_{\mathrm{s,k,h}}^{\mathrm{m,t}}$ **Where net uncovered consumption = 0:**	Hourly (type 'DP' records only. See: "Format Spec. for Settlement Statement Files and Data Files" for further details)	Either Way	N/A	N/A	N/A	N/A			Eligibility, rates, and other implementation details subject to government regulation.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				$\Sigma_{T,m}(\mathrm{EMP}_h^{\mathrm{m,t}} - \mathrm{FP}_h^{m}) \times (-\mathrm{AQEI}_{\mathrm{k,h}}^{\mathrm{m,t}})$ **SUBJECT TO:** Net uncovered consumption = $\mathrm{MAX}[\Sigma_{T,m}(\mathrm{AQEW}_{\mathrm{k,h}}^{\mathrm{m,t}} - \Sigma_s \mathrm{BCQ}_{\mathrm{s,k,h}}^{\mathrm{m,t}}),0]$ **Fixed Energy Rate Settlement Amount (non-dispatchable locations):** **Where net uncovered consumption > 0:** $(\mathrm{HOEP}_h - \mathrm{FP}_h^{m}) \times \Sigma_{\mathrm{m,T}}(\mathrm{AQEW}_{\mathrm{k,h}}^{\mathrm{m,t}} - \mathrm{AQEI}_{\mathrm{k,h}}^{\mathrm{m,t}} - \Sigma_s \mathrm{BCQ}_{\mathrm{s,k,h}}^{\mathrm{m,t}})$ **Where net uncovered consumption = 0:** $(\mathrm{HOEP}_h - \mathrm{FP}_h^{m}) \times \Sigma_{\mathrm{m,T}}(-\mathrm{AQEI}_{\mathrm{k,h}}^{\mathrm{m,t}})$ **SUBJECT TO:** $\text{Net uncovered consumption} = \mathrm{MAX}[\Sigma_{\mathrm{T,m}}(\mathrm{AQEW}_{\mathrm{k,h}}^{\mathrm{m,t}} - \Sigma_s \mathrm{BCQ}_{\mathrm{s,k,h}}^{\mathrm{m,t}}),0]$ **SUBJECT TO:** $\text{Net uncovered consumption} = \mathrm{MAX}[\Sigma_{\mathrm{T,m}}(\mathrm{AQEW}_{\mathrm{k,h}}^{\mathrm{m,t}} - \Sigma_s \mathrm{BCQ}_{\mathrm{s,k,h}}^{\mathrm{m,t}}),0]$									

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
141	Fixed Wholesale Charge Rate Settlement Amount	N/A	N/A	**<u>** CALCULATIONS FOR *CHARGE TYPE* 141 END MARCH 31, 2005 **</u>** **<u>NOTE:</u>** The equations identified below apply to *distributors*, low volume and designated consumers (as defined in Bill 4 and associated regulations) in *the IESO-administered market.* For *distributors* an additional *charge type* 141 record is provided to reflect any monthly submission of IMO_FORM_1562. See IMO_FORM_1562 for further details. $\mathrm{TD}_{k,C} - \sum_{M,H}\mathrm{AQEW}_{k,h,}{}^{m,t} * (\mathrm{FPC})$ Where: 'H' is all *settlement hours* 'h' during the *billing period;* and, 'C' is a designated group of *charge types* 'c' prescribed by government regulation (and associated rulings by the *Ontario Energy Board*) and consisting of the cumulative sum of the following *charge types*: **150, 155, 168, 170, 182, 183, 184, 250, 252, 254, 450, 452, 454, 550, 753, 9990**	Monthly	Either Way	N/A	N/A	N/A	N/A			Eligibility, rates, and other implementation details subject to government regulation.
142	Regulated Price Plan Settlement Amount	N/A	N/A	**<u>NOTE:</u>** The equation identified below applies to low volume and designated consumers (as defined in	Monthly	Due LDCs Either way	13	N/A	N/A	N/A	May 1, 2023		Eligibility, rates, and other implementation details subject to

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				Ontario Energy Board Act, 1998 and associated regulations) in the *IESO-administered market*. For *distributors, charge type* 142 is applied once a month based on the values submitted by the *distributor* via On-line settlement forms: "Tiered Regulated Price Plan for Conventional Meters vs. Market Price Variance", "Standard TOU Regulated Price Plan for Smart Meters vs. Market Price Variance", "ULO Regulated Price Plan for Smart Meters vs. Market Price Variance" and "Regulated Price Plan – Final Variance Settlement Amount". **Tiered Regulated Price Plan Amount:** $NEMSC_{k,H} - \{ MIN [TLQ , \sum_H {}^{M,T} (AQEW_{k,h}{}^{m,t} - AQEI_{k,h}{}^{m,t} - \Sigma_s BCQ_{s,k,h}{}^{m,t})] \times RPP_{l=1} + MAX [0, \sum_H {}^{M,T} (AQEW_{k,h}{}^{m,t} - AQEI_{k,h}{}^{m,t} - \Sigma_s BCQ_{s,k,h}{}^{m,t}) - TLQ] \times RPP_{l=2} \}$									government and OEB regulations.
143	NUG Contract Adjustment	N/A	N/A	Manual entry based on the values submitted by *OEFC* via On-line	Monthly	Due *OEFC*	13	N/A	N/A	N/A			Eligibility, rates, and other implementation details subject to

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
	Settlement Amount			settlement form "NUG Adjustment Amount Information", subject to Regulation.									government regulation.
144	Regulated Nuclear Generation Adjustment Amount	N/A	N/A	**For dispatchable *delivery points*:** $(GRP - EMP_h^{m,t}) \times AQEI_{k,h}^{m,t}$ **For non-dispatchable *delivery points*:** $(GRP - HOEP_h) \times \Sigma^T AQEI_{k,h}^{m,t}$ Where 'T' is the set of 12 *metering intervals* 't' during *settlement hour* 'h'.	Interval or Hourly	Due OPG	13	N/A	N/A	N/A			Eligibility, rates, and other implementation details subject to government regulation.
145	Regulated Hydroelectric Generation Adjustment Amount	N/A	N/A	$NEMSC_{k,H} - \{\sum_H^{M,T}[(MWAvg_T \times GRP) + ((AQEI_{k,h}^{m,t} - AQEW_{k,h}^{m,t}) - MWAvg_T) \times EMP_h^{m,t}]\}$ Where 'M' is the set of all *delivery points* 'm' of OPG's regulated hydroelectric generating stations. 'T' is the set of 12 *metering intervals* 't' during *settlement hour* 'h'. 'H' is the set of all *settlement hours* 'h' in the month.	Monthly	Due OPG	13	N/A	N/A	N/A			Eligibility, rates, and other implementation details subject to *OEB* regulation.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				MWAvg is the average hourly net energy production within a given month.									
146	Global Adjustment Settlement Amount	N/A	N/A	**<u>**CALCULATIONS FOR *CHARGE TYPE* 146 END DECEMBER 31, 2010. *CHARGE TYPE* 146 REPLACED BY *CHARGE TYPES* 147 AND 148 EFFECTIVE JANUARY 1, 2011.**</u> For Fort Frances Power Corporation Distribution Inc.: $\Sigma_{\mathrm{H,M,C}}\mathrm{TD} \times (\Sigma_{H}{}^{\mathrm{M,T}}\mathrm{AQEW}_{\mathrm{k,h}}{}^{\mathrm{m,t}} + \mathrm{EGEI}_{k} - \mathrm{EEQ}) / (\Sigma_{\mathrm{K,H}}{}^{\mathrm{M,T}}\mathrm{AQEW}_{\mathrm{k,h}}{}^{\mathrm{m,t}} + \Sigma_{K}\mathrm{EGEI}_{k} - \mathrm{EEQ})$ For other *market participant*s: $\Sigma_{\mathrm{H,M,C}}\mathrm{TD} \times (\Sigma_{H}{}^{\mathrm{M,T}}\mathrm{AQEW}_{\mathrm{k,h}}{}^{\mathrm{m,t}} + \mathrm{EGEI}_{k}) / (\Sigma_{\mathrm{K,H}}{}^{\mathrm{M,T}}\mathrm{AQEW}_{\mathrm{k,h}}{}^{\mathrm{m,t}} + \Sigma_{K}\mathrm{EGEI}_{k} - \mathrm{EEQ})$ Where ‘H’ is the set of all *settlement hours* ‘h’ in the month.	Monthly	Due MPs	13	N/A	N/A	N/A			Eligibility, rates, and other implementation details subject to government regulation.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				Where 'K' is the set of all *market participants* 'k'. Where 'M' is the set of all *delivery points* 'm' of *market participant* 'k'. Where 'C' is the set of the following *charge types* 'c': **193, 194, 195, 197, 198, 1380, 1381, 1382, 1383, 1384, 1385, 1386, 1390, 1391, 1392, 1393, 1394, 1395, 1396, 1397, 1398, 1450, 1460, 1461, 1462 and 1464.**									
147	Class A – Global Adjustment Settlement Amount	N/A	N/A	$\Sigma_{H,M,C}TD * PDF_{k,m,d}$ Where 'd' is the ratio of the number of days in the month the Peak Demand Factor was effective compared to the total number of days in the month and 'C' is the set of the following *charge types* 'c': **193, 194, 195, 1380, 1381, 1382, 1383, 1384, 1385, 1386, 1390, 1391, 1392, 1393, 1394, 1395, 1396, 1397, 1398, 1466, 1450, 1460, 1461, 1462,**	Monthly	Either Way	13	N/A	N/A	N/A			Eligibility, rates, and other implementation details subject to government regulation. Charge type 147 is also used to settle Interruptible Rate Pilot participants starting with trade date July 1, 2023.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				1464, 1468, 1469, 1471, 1472, 1473, 1474, 1475.									
148	Class B – Global Adjustment Settlement Amount	N/A	N/A	For Fort Frances Power Corporation Distribution Inc.: $(\Sigma_{\mathrm{H,M,C}}\mathrm{TD} - \mathrm{TD}_{147}) \times \mathrm{MAX}((\Sigma_H{}^{\mathrm{M,T}}\mathrm{AQEW}_{\mathrm{k,h}}{}^{\mathrm{m,t}} + \mathrm{EGEI}_k - \mathrm{EEQ}),0)$ / Class B Load For other Class B *Market Participant*s and Distributors: $(\Sigma_{\mathrm{H,M,C}}\mathrm{TD} - \mathrm{TD}_{147}) \times \mathrm{MAX}((\Sigma_H{}^{\mathrm{M,T}}\mathrm{AQEW}_{\mathrm{k,h}}{}^{\mathrm{m,t}} + \mathrm{EGEI}_k - \mathrm{GA_AQEW}_{\mathrm{g,k,h,M}}{}^{\mathrm{m,t}} - \mathrm{PGS}_{\mathrm{h,M}}),0)$ Class B Load Class B Load = $(\Sigma_K(\mathrm{MAX}(\Sigma_H{}^{\mathrm{M,T}}\mathrm{AQEW}_{\mathrm{k,h}}{}^{\mathrm{m,t}} + \mathrm{EGEI}_k - \mathrm{EEQ} - \Sigma_H{}^{\mathrm{M,T}}\mathrm{GA_AQEW}_{\mathrm{g,k,h,M}}{}^{\mathrm{m,t}} - \Sigma_H\mathrm{PGS}_{\mathrm{h,M}},0))) - \Sigma_K U_k$ Where ‘H’ is the set of all *settlement hours* ‘h’ in the month. Where ‘K’ is the set of all *market participants* ‘k’.	Monthly	Either Way	13	N/A	N/A	N/A			Eligibility, rates, and other implementation details subject to government regulation.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				Where 'M' is the set of all *delivery points* 'm' of *market participant* 'k'. Where 'C' is the set of the following *charge types* 'c': **193, 194, 195, 1380, 1381, 1382, 1383, 1384, 1385, 1386, 1390, 1391, 1392, 1393, 1394, 1395, 1396, 1397, 1398, 1466, 1450, 1460, 1461, 1462, 1464, 1468, 1469, 1471, 1472, 1473, 1474, 1475.**									
149	Regulated Price Plan Retailer Settlement Amount	N/A	N/A	Manual entry based on the values submitted by *market participants* via On-line settlement form "Retailer Payments for Contract Price vs. HOEP for Regulated Consumers with a Retail Contract".	Monthly	Due LDCs	13	N/A	N/A	N/A			Implementation details subject to government regulation.
150	Net Energy Market Settlement Uplift	N/A	9.3.9.1	$\sum_{C}^{M,T} TD_{k,h,c} \times [(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t} + RQ_{k,h}^{m,t}) / \sum_{k}^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t})]$ Where: 'C' is the set of the following *charge types* 'c' as follows: **100, 101, 103, 104, 1131**	Hourly	Either Way	13	N/A	0	13	May 1, 2002	April 30, 2023	

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				'T' is the set of 12 *metering intervals* 't' during *settlement hour* 'h'. Where $RQ_{k,h}^{m,t}$ is a reallocated quantity whereby *market participant* 'k' is a party to one or more *physical bilateral contracts* for *settlement hour* 'h' in which the NEMSC component of *hourly uplift* is to be reallocated between *market participant* 'k' and the other *market participant* that is a party to the contract in which: $RQ_{k,h}^{m,t} = \sum_{s,b} [BCQ_{k,b,h}^{m,t} - BCQ_{s,k,h}^{m,t}]$									
150	Net Energy Market Settlement Uplift	N/A	9.3.9.1	$\sum_{c}^{M,T} TD_{k,h,c} x [(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t} + RQ_{k,h}^{m,t}) / \sum_{k}^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t})]$ Where: 'C' is the set of the following *charge types* 'c' as follows: **1101, 1103, 1111, 1113, 1114, 1115, 103, 104, 1131** 'T' is the set of 12 *metering intervals* 't' during *settlement hour* 'h'.	Hourly	Either Way	13	N/A	0	13	May 1, 2023		

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				Where $RQ_{k,h}^{m,t}$ is a reallocated quantity whereby *market participant* 'k' is a party to one or more *physical bilateral contracts* for *settlement hour* 'h' in which the NEMSC component of *hourly uplift* is to be reallocated between *market participant* 'k' and the other *market participant* that is a party to the contract in which: $RQ_{k,h}^{m,t} = \sum_{s,b} [BCQ_{k,b,h}^{m,t} - BCQ_{s,k,h}^{m,t}]$									
155	Congestion Management Settlement Uplift	N/A	9.3.5.2 and 9.3.5.7	$\sum_{c}^{M,T} TD_{k,h,(105,106,107,108,122,124,1050,} \times [(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t} + RQ_{k,h}^{m} / \sum_{k}^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t})]$ Where 'T' is the set of 12 *metering intervals*'t' during *settlement hour* 'h'. Where $RQ_{k,h}^{m,t}$ is a reallocated quantity whereby *market participant* 'k' is a party to one or more *physical bilateral contracts* for *settlement hour* 'h' in which the CMSC component of *hourly uplift* is to be reallocated between *market*	Hourly or Monthly (see 9.3.5.7)	Either Way	13	N/A	0	13			Pursuant to market rules, Section 9.3.5.7, during an interim period, the disbursements of charge type 105 amounts adjusted as per Section 9.3.5.6 may be made on a monthly basis.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				participant 'k' and the other *market participant* that is a party to the contract in which: $RQ_{k,h}^{m,t} = \sum_{s,b} [BCQ_{k,b,h}^{m,t} - BCQ_{s,k,h}^{m,t}]$									
161	Northern Pulp and Paper Mill Electricity Transition Program Balancing Amount	N/A	N/A	$\Sigma_K TD_{k,111}$ Where 'k' is part of a subset of eligible *market participants* 'k'.	Quarterly	Due *IESO*	0	N/A	N/A	N/A			This program ends on September 30, 2010.
162	Ontario Power Generation Rebate Debit	N/A	N/A	**** CALCULATIONS FOR *CHARGE TYPE* 162 END April 30, 2009 **** Payment $(n) = \sum_H [(HOEP_h - ORL) \times (ONPAO_h \times 0.85 - PAA) +$ $(PAP - PAORL) \times PAA)]$ OPG rebate (n) = Max [0, Payment (n) – Payment (n−1) + NCF (n−1)] Where:	May 1, 2006 to April 30, 2009	Due *IESO*	N/A	N/A	N/A	N/A			The OPG rebate quarterly payment will be based on a cumulative calculation commencing May 1, 2006 to the end of each quarter less the same cumulative calculation to the end of the previous quarter. Where the payment formula results in an amount owing to OPG for any quarter, no such payment will be

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				'H' is the set of all *settlement hours* 'h' from May 1, 2006 to the end of the applicable quarter. 'n' is the current quarter. 'n−1' is the previous quarter. NCF is the negative amount carried forward and calculated as NCF (n) = Min [0, Payment (n) – Payment (n−1) + NCF (n−1)]									made to OPG and any such amount will be carried forward into subsequent quarters.
163	Additional Compensation for Administrative Pricing Debit.	N/A	7.8.4A.16 or 7.8.4A.10 or 7.13.6.2, and 9.4.8	$\sum_{c,H}^{M,T} TD_{k,H,(113)} \times [(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}) / \sum_{k,H}^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t})]$ Where 'H' is the set of all *settlement hours* 'h' in the month. Where 'T' is the set of all *metering intervals* 't' in the set of all *settlement hours* 'H'.	Monthly	Due *IESO*	13	N/A	0	13			This charge will still be used for market suspension events.
164	Outage Cancellation/ Deferral Debit.	N/A	5.6.7.4 and 9.4.8.1.3	$\sum_{c,H}^{M,T} TD_{k,H,(114)} \times [(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}) / \sum_{k,H}^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t})]$ Where 'H' is the set of all *settlement hours* 'h' in the month.	Monthly	Due *IESO*	13	N/A	0	13			

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				Where 'T' is the set of all *metering intervals* 't' in the set of all *settlement hours* H.									
165	Unrecoverable Testing Costs Debit	N/A	9.4.8.1.1 and 4.5.3.4	$= \sum_{H,c}{}^{M,T} TD_c \times [(AQEW_{k,h}{}^{m,t} + SQEW_{k,h}{}^{i,t}) / \sum_{k,H}{}^{M,T} (AQEW_{k,h}{}^{m,t} + SQEW_{k,h}{}^{i,t})]$ Where 'H' is the set of all *settlement hours* 'h' in the month. Where 'T' is the set of all *metering intervals* 't' in the set of all *settlement hours* 'H'.	Monthly	Due *IESO*	13	N/A	0	13			
166	Tieline Reliability Maintenance Debit	N/A	9.4.8.1.2 and 5.5.3.4	$= \sum_{H,c}{}^{M,T} TD_c \times [(AQEW_{k,h}{}^{m,t} + SQEW_{k,h}{}^{i,t}) / \sum_{k,H}{}^{M,T} (AQEW_{k,h}{}^{m,t} + SQEW_{k,h}{}^{i,t})]$ Where 'H' is the set of all *settlement hours* 'h' in the month. Where 'T' is the set of all *metering intervals* 't' in the set of all *settlement hours* 'H'.	Monthly	Due *IESO*	13	N/A	0	13			
167	Emergency Energy Debit	N/A	9.4.8.1.5 9.4.2.3A and 5.2.3.3A	$= \sum_{H,c}{}^{M,T} TD_c \times [(AQEW_{k,h}{}^{m,t} + SQEW_{k,h}{}^{i,t}) / \sum_{k,H}{}^{M,T} (AQEW_{k,h}{}^{m,t} + SQEW_{k,h}{}^{i,t})]$	Monthly	Due *IESO*	13	N/A	0	13			

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				Where 'H' is the set of all *settlement hours* 'h' in the month. Where 'c' is any payments made for *emergency energy* during the applicable period. Where 'T' is the set of all *metering intervals* 't' in the set of all *settlement hours* 'H'.									
168	TR Market Shortfall Debit	N/A	9.4.8.1.7 and 9.6.14.5.2	**For loads:** $\mathrm{TRCAC}_k = \mathrm{TRCAD}_L \times \sum_H{}^{\mathrm{M,T}} [(\mathrm{AQEW}_{\mathrm{k,h}}{}^{\mathrm{m,t}}) / \sum_{\mathrm{K,H}}{}^{\mathrm{M,T}} (\mathrm{AQEW}_{\mathrm{k,h}}{}^{\mathrm{m,t}})]$ **For exporters:** $\mathrm{TRCAC}_k = \mathrm{TRCAD}_E \times \sum_H{}^{\mathrm{I,T}} [(\mathrm{SQEW}_{\mathrm{k,h}}{}^{\mathrm{i,t}}) / \sum_{\mathrm{K,H}}{}^{\mathrm{I,T}} (\mathrm{SQEW}_{\mathrm{k,h}}{}^{\mathrm{i,t}})]$ **Where** $\mathrm{TRCAD}_L = (\sum_K \mathrm{TD}_C / \sum_K \mathrm{TD}_{\mathrm{C,C1}}) \times \mathrm{TRCARTRCAD}_E = (\sum_K \mathrm{TD}_{\mathrm{C1}} / \mathrm{å}_K \mathrm{TD}_{\mathrm{C,C1}}) \times \mathrm{TRCAR}$ Where 'C' is the set of all *monthly service charge types c as follows: 650,651,652.*	Monthly	Due *IESO*	13	N/A	0	13			

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				Where 'C1' is the set of all *monthly export transmission charge types c as follows:653.* Where 'H' is the set of all *settlement hours* 'h' in the month. Where 'T' is the set of all *metering intervals* 't' in the set of all *settlement hours* 'H'. Where 'M' is the set of all *delivery points* 'm', excluding any *intertie metering points*. Where 'I' is the set of all *intertie metering points* 'i'. Where 'K' is the set of all *market participants* 'k'.									
169	Station Service Reimbursement Debit	N/A	9.4.8.1.6 and 9.2.1A.12.2 (a)	$= \sum_{H,c}{}^{M,T} TD_c \times [(AQEW_{k,h}{}^{m,t} + SQEW_{k,h}{}^{i,t}) / \sum_{k,H}{}^{M,T} (AQEW_{k,h}{}^{m,t} + SQEW_{k,h}{}^{i,t})]$ Where 'H' is the set of all *settlement hours* 'h' in the month. Where 'T' is the set of all *metering intervals* 't' in the set of all *settlement hours* 'H'.	Monthly	Due *IESO*	13	N/A	0	13	June 1, 2002	April 30, 2023	
169	Station Service Reimbursement Debit	N/A	9.4.8.1.6 and	$= \sum_{H,c}{}^{M,T} TD_c$	Monthly	Due *IESO*	13	N/A	0	13	May 1, 2023		

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
			9.2.1A.12.2 (a)	$-\text{GSSR_AQEW}_{k,h}^{i,t}) / \sum_{k,H}^{M,T}(\text{AQEW}_{k,h}$ $\text{SQEW}_{k,h}^{i,t} - \text{GSSR_AQEW}_{k,h}^{i,t})]$ Where 'H' is the set of all *settlement hours* 'h' in the month. Where 'T' is the set of all *metering intervals* 't' in the set of all *settlement hours* 'H'.									
170	Local Market Power Rebate	N/A	9.4.8.2.2 9.4.8.2.3 9.3.8A.5 9.3.8A.6 and Ch. 7, Appendix 7.6	$= \sum_{H,C}^{M,T}\text{TD}_c \times [(\text{AQEW}_{k,h}^{m,t} + \text{SQEW}_{k,h}^{i,t}) / \sum_{k,H}^{M,T}(\text{AQEW}_{k,h}^{m,t} + \text{SQEW}_{k,h}^{i,t})]$ Where 'c' denotes *charge type* 120 and that portion of *charge type* 130 related to the IOG OFFSET *settlement amount.* Where 'H' is the set of all *settlement hours* 'h' in the month. Where 'T' is the set of all *metering intervals* 't' in the set of all *settlement hours* 'H'.	Monthly	Due MP	13	N/A	0	13			
171	Northern Industrial Electricity Rate Program Balancing Amount	N/A	N/A	$\Sigma_K \text{TD}_{k,121}$ Where 'k' is part of a subset of eligible *market participants* 'k'.	Quarterly	Due *IESO*	0	N/A	N/A	N/A	July 31, 2011	April 30, 2022	

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
171	Northern Energy Advantage Program Balancing Amount	N/A	N/A	$\Sigma_K \mathrm{TD}_{k,121}$ Where 'k' is part of a subset of eligible *market participants* 'k'.	Quarterly	Due *IESO*	0	N/A	N/A	N/A	July 31, 2022		
173	MACD Enforcement Activity Balancing Amount	N/A	N/A	$\Sigma K \mathrm{TD}_{k123}$ Where 'K' is the set of all *market participants* 'k'. Where TD_{k123} is the *settlement amount* of *charge type* 123 for the month for *market participant* 'k'.	Monthly	Due *IESO*	0	N/A	N/A	N/A			
183	Generation Cost Guarantee Recovery Debit	N/A	9.4.8.1.9	$= \sum_{H,C}{}^{M,T} \mathrm{TD}_{h,c} x\ [(\mathrm{AQEW}_{k,h}{}^{m,t} + \mathrm{SQEW}_{k,h}{}^{i,t}) / \sum_{k,H}{}^{M,T} (\mathrm{AQEW}_{k,h}{}^{m,t} + \mathrm{SQEW}_{k,h}{}^{i,t})]$ Where: 'C' is the set of the following *charge types* 'c' as follows: **133, 137** 'H' is the set of all *settlement hours* 'h' in the month.	Monthly	*IESO*	13	N/A	0	13			

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				'T' is the set of all *metering intervals* 't' in the set of all *settlement hours* 'H'.									
184	Demand Response Debit	N/A	9.4.7C 9.4.7F	$\sum_{k,H,}(TD_{134}) \times [(AQEW_{k,h}{}^{m,t} + SQEW_{k,h}{}^{i,t}) / \sum_{k,H}{}^{M,T} (AQEW_{k,h}{}^{m,t} + SQEW_{k,h}{}^{i,t})]$ Where: 'H' is all *settlement hours* 'h' during the *billing period*.	Monthly	Either way	13	N/A	0	5			TDRP and ELRP suspended by the *IESO*.
186	Intertie Failure Charge Rebate	$HUSA_{k,h}$	9.3.9.1	$\sum_{C}{}^{M,T} TD_{c} x [(AQEW_{k,h}{}^{m,t} + SQEW_{k,h}{}^{i,t} + RQ_{k,h}{}^{m,t}) / \sum_{k}{}^{M,T} (AQEW_{k,h}{}^{m,t} + SQEW_{k,h}{}^{i,t})]$ Where: 'C' is the set of the following *charge types* 'c' as follows: **135, 136, 1134, 1135, 1136** 'T' is the set of 12 *metering intervals* 't' during *settlement hour* 'h'. Where $RQ_{k,h}{}^{m,t}$ is a reallocated quantity whereby *market participant* 'k' is a party to one or more *physical bilateral contracts* for *settlement hour* 'h' in which the IFCR component of *hourly uplift* is to be reallocated between *market*	Hourly	Due MP	13	N/A	0	13			

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				participant 'k' and the other *market participant* that is a party to the contract in which: $RQ_{k,h}^{m,t} = \sum_{s,b} [BCQ_{k,b,h}^{m,t} - BCQ_{s,k,h}^{m,t}]$									
190	Fixed Energy Rate Balancing Amount	N/A	N/A	**** *CHARGE TYPE* 190 REPLACED BY *CHARGE TYPE* 192 EFFECTIVE JANUARY 1, 2005 **** $\sum_{k,H,c}(TD_{140})$ Where: 'H' is all *settlement hours* 'h' during the *trading day* for all *trading days* during the interim period beginning December 1, 2002.	Hourly (type 'DP' records only. See: "Format Spec. for Settlement Statement Files and Data Files" for further details)	Either Way	N/A	N/A	N/A	N/A			Eligibility, rates, and other implementation details subject to government regulation.
191	Fixed Wholesale Charge Rate Balancing Amount	N/A	N/A	**** CALCULATIONS FOR *CHARGE TYPE* 191 END MARCH 31, 2005 **** $\sum_{k,H,c}(TD_{141})$ Where: 'H' is all *settlement hours* 'h' during the *billing period*.	Monthly	Either Way	N/A	N/A	N/A	N/A			Eligibility, rates, and other implementation details subject to government regulation.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
192	Regulated Price Plan Balancing Amount	N/A	N/A	$\Sigma_K \mathrm{TD}_{k,142}$ Where 'K' is the set of all *market participants* 'k'. Where $\mathrm{TD}_{k,142}$ is the total *settlement amount* of *charge type* 142 for the month for *market participant* 'k'.	Monthly	Due *IESO*	0	N/A	N/A	N/A			Implementation details subject to government regulation.
193	NUG Contract Adjustment Balancing Amount	N/A	N/A	TD_{143}	Monthly	Due *IESO*	0	N/A	N/A	N/A			Implementation details subject to government regulation.
194	Regulated Nuclear Generation Balancing Amount	N/A	N/A	TD_{144}	Interval or Hourly	Due *IESO*	0	N/A	N/A	N/A			Implementation details subject to government regulation.
195	Regulated Hydroelectric Generation Balancing Amount	N/A	N/A	TD_{145}	Monthly	Due *IESO*	0	N/A	N/A	N/A			Implementation details subject to *OEB* regulation.
196	Global Adjustment Balancing Amount	N/A	N/A	$\Sigma_{K,} \mathrm{TD}_{k,147,\ 148\ -\Sigma 197}$ Where 'K' is the set of all *market participants* 'k'. Where $\mathrm{TD}_{k,147,\ 148}$is the *settlement amount* of *charge type* 147 and 148 for the month for *market participant* 'k'.	Monthly	Due *IESO*	0	N/A	N/A	N/A			Eligibility, rates, and other implementation details subject to government regulation.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
197	Global Adjustment - Special Programs Balancing Amount	N/A	N/A	$\Sigma_K \mathrm{TD}_{k,1466}$ Where 'K' is the set of all *market participants* 'k'. Where $\mathrm{TD}_{k,1466}$ is the *settlement amount* of *charge type* 1466 for the month for *market participant* 'k'.	Monthly	Due *IESO*	0	N/A	N/A	N/A			Implementation details subject to government regulation.
198	Renewable Generation Balancing Amount	N/A	N/A	**** CALCULATIONS FOR *CHARGE TYPE* 198 END DECEMBER 31, 2010 **.** $\Sigma_K \mathrm{TD}_{k,148}$ Where 'K' is the set of all *market participants* 'k'. Where $\mathrm{TD}_{k,148}$ is the *settlement amount* of *charge type* 148 for the month for *market participant* 'k'.	Pending	Due *IESO*	0	N/A	N/A	N/A			Implementation details subject to government regulation.
199	Regulated Price Plan Retailer Balancing Amount	N/A	N/A	$\Sigma_K \mathrm{TD}_{k,149}$ Where 'K' is the set of all *market participants* 'k'. Where $\mathrm{TD}_{k,149}$ is the *settlement amount* of *charge type* 149 for the month for *market participant* 'k'.	Monthly	Due *IESO*	0	N/A	N/A	N/A			Implementation details subject to government regulation.
200	10 Minute Spinning Reserve Market	ORSCk,h	9.3.4.1	$\sum m,t,r \mathrm{AQORr,k,hm,t} \times \mathrm{PRORr,hm,t}$	Interval	Due MP	13	13	N/A	N/A			

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
	Settlement Credit												
201	10 Minute Spinning Reserve Market Shortfall Rebate	$HUSA_h$	9.3.9.1	$\sum_c^{M,T} TD_{k,h,(251)} x\ [(AQEW_{k,h}^{m,t} + SQEW_h^{i,t} + RQ_{k,h}^{m,t}) / \sum_k^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t})]$ Where 'T' is the set of 12 *metering intervals* 't' during *settlement hour* 'h'. Where $RQ_{k,h}^{m,t}$ is a reallocated quantity whereby *market participant* 'k' is a party to one or more *physical bilateral contracts* for *settlement hour* 'h' in which the *operating reserve* component of *hourly uplift* is to be reallocated between *market participant* 'k' and the other *market participant* that is a party to the contract in which: $RQ_{k,h}^{m,t} = \sum_{s,b} [BCQ_{k,b,h}^{m,t} - BCQ_{s,k,h}^{m,t}]$	Hourly	Due MP	13	N/A	0	13			
202	10 Minute Non-spinning Reserve Market Settlement Credit	$ORSC_{k,h}$	9.3.4.1	$\sum_{m,t,r} AQOR_{r,k,h}^{m,t} \times PROR_{r,h}^{m,t}$	Interval	Due MP	13	13	N/A	N/A			

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
203	10 Minute Non-spinning Reserve Market Shortfall Rebate	$HUSA_h$	9.3.9.1	$\sum_c^{M,T} TD_{k,h,(253)} \times [(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t} + RQ_{k,h}^{m,t}) / \sum_k^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t})]$ Where 'T' is the set of 12 *metering intervals* 't' during *settlement hour* 'h'. Where $RQ_{k,h}^{m,t}$ is a reallocated quantity whereby *market participant* 'k' is a party to one or more *physical bilateral contracts* for *settlement hour* 'h' in which the *operating reserve* component of *hourly uplift* is to be reallocated between *market participant* 'k' and the other *market participant* that is a party to the contract in which: $RQ_{k,h}^{m,t} = \sum_{s,b} [BCQ_{k,b,h}^{m,t} - BCQ_{s,k,h}^{m,t}]$	Hourly	Due MP	13	N/A	0	13			
204	30 Minute Operating Reserve Market Settlement Credit	$ORSC_{k,h}$	9.3.4.1	$\sum_{m,t,r} AQOR_{r,k,h}^{m,t} \times PROR_{r,h}^{m,t}$	Interval	Due MP	13	13	N/A	N/A			
205	30 Minute Operating Reserve Market Shortfall Rebate	$HUSA_h$	9.3.9.1	$\sum_c^{M,T} TD_{k,h,(255)} \times [(AQEW_{k,h}^{m,t}$	Hourly	Due MP	13	N/A	0	13			

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				$(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{t,t})]$ Where 'T' is the set of 12 *metering intervals* 't' during *settlement hour* 'h'. Where $RQ_{k,h}^{m,t}$ is a reallocated quantity whereby *market participant* 'k' is a party to one or more *physical bilateral contracts* for *settlement hour* 'h' in which the *operating reserve* component of *hourly uplift* is to be reallocated between *market participant* 'k' and the other *market participant* that is a party to the contract in which: $RQ_{k,h}^{m,t} = \sum_{s,b} [BCQ_{k,b,h}^{m,t} - BCQ_{s,k,h}^{m,t}]$									
206	10-Minute spinning non-Accessibility Settlement Amount	$ORSCB_{r,k,h}$	9.3.4.2-9.3.4.3	**For *dispatchable loads* and non-aggregated *generators:*** $MIN(0,(TAOR_{k,h}^{m,t} - AQOR_{r1,k,h}^{m,t}) \times PROR_{r1,h}^{m,t})$ Where: $TAOR_{k,h}^{m,t} =$ $MAX(0,AQEW_{k,h}^{m,t} - MC_{h}^{m,t})$ for *dispatchable loads*	Interval	Due IESO	13	N/A	N/A	N/A	May 1, 2023		Please refer to MR-00467

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				or, $MAX(0,MAX_CAP_{k,h}^{m,t} - AQEI_{k,h}^{m,t})$ for *generators* **For aggregated generators:** $ORIA_CA_{r1,k,h}^{M,t} \times ORCF_{r1,k,h}^{m,t} \times PROR_{r1,h}^{m,t}$ Where: $ORIA_CA_{r1,k,h}^{M,t} = MIN(0,TAOR_CA_{k,h}^{M,t} - \sum_M AQOR_{r1,k,h}^{m,t})$ $TAOR_CA_{k,h}^{M,t} = MAX(0,\sum_M (MAX_CAP_{k,h}^{m,t} - AQEI_{k,h}^{m,t}))$ $ORCF_{r1,k,h}^{m,t} = ORIA_{r1,k,h}^{m,t} / (\sum_{M1} ORIA_{r1,k,h}^{m,t})$, and M1 represents the set of all delivery points 'm' offering 10-minute synchronized OR $ORIA_{r1,k,h}^{m,t} = MIN(0,(TAOR_{k,h}^{m,t} - AQOR_{r1,k,h}^{m,t}))$								

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
208	10-Minute non-Spinning non-Accessibility Settlement Amount	$ORSCB_{r,k,h}$	9.3.4.2-9.3.4.3	**For *dispatchable loads* and non-aggregated *generators:*** $MIN(0,(MAX(0,TAOR_{k,h}^{m,t} – AQOR_{r1,k,h}^{m,t}) - AQOR_{r2,k,h}^{m,t}) \times PROR_{r2,h}^{m,t})$ Where: $TAOR_{k,h}^{m,t} =$ $MAX(0,AQEW_{k,h}^{m,t} – MC_{h}^{m,t})$ for *dispatchable loads* *or,* $MAX(0,MAX_CAP_{k,h}^{m,t} – AQEI_{k,h}^{m,t})$ for *generators* **For aggregated generators:** $ORIA_CA_{r2,k,h}^{M,t} \times ORCF_{r2,k,h}^{m,t} \times PROR_{r2,h}^{m,t}$ Where: $ORIA_CA_{r2,k,h}^{M,t} = MIN(0,TAOR_CA_{k,h}^{M,t} - \sum_{M} AQOR_{r2,k,h}^{m,t})$ $TAOR_CA_{k,h}^{M,t} =$	Interval	Due IESO	13	N/A	N/A	N/A	May 1, 2023		Please refer to MR-00467

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				$MAX(0,\sum_M (MAX_CAP_{k,h}^{m,t} - AQEI_{k,h}^{m,t}))$ $ORCF_{r2,k,h}^{m,t} = ORIA_{r2,k,h}^{m,t} / (\sum_{M2} ORIA_{r2,k,h}^{m,t})$, and M2 represents the set of all delivery points 'm' offering 10-minute non-synchronized OR $ORIA_{r2,k,h}^{m,t} = MIN(0,(TAOR_{k,h}^{m,t} - AQOR_{r2,k,h}^{m,t}))$									
210	30-Minute non-Accessibility Settlement Amount	$ORSCB_{r,k,h}$	9.3.4.2-9.3.4.3	**For *dispatchable loads* and non-aggregated *generators:*** $MIN(0,(MAX(0,TAOR_{k,h}^{m,t} - AQOR_{r1,k,h}^{m,t} - AQOR_{r2,k,h}^{m,t}) - AQOR_{r3,k,h}^{m,t}) \times PROR_{r3,h}^{m,t})$ Where: $TAOR_{k,h}^{m,t} =$ $MAX(0,AQEW_{k,h}^{m,t} - MC_h^{m,t})$ for *dispatchable loads* *or,* $MAX(0,MAX_CAP_{k,h}^{m,t} - AQEI_{k,h}^{m,t})$ for *generators* **For aggregated generators:**	Interval	Due IESO	13	N/A	N/A	N/A	May 1, 2023		Please refer to MR-00467

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				$ORIA_CA_{r3,k,h}^{M,t} \times ORCF_{r3,k,h}^{m,t} \times PROR_{r3,h}^{m,t}$ Where: $ORIA_CA_{r3,k,h}^{M,t} = MIN(0,TAOR_CA_{k,h}^{M,t} - \sum_M AQOR_{r3,k,h}^{m,t})$ $TAOR_CA_{k,h}^{M,t} = MAX(0,\sum_M (MAX_CAP_{k,h}^{m,t} – AQEI_{k,h}^{m,t}))$ $ORCF_{r3,k,h}^{m,t} = ORIA_{r3,k,h}^{m,t} / (\sum_{M3} ORIA_{r3,k,h}^{m,t})$, and M3 represents the set of all delivery points 'm' offering 30-minute OR $ORIA_{r3,k,h}^{m,t} = MIN(0,(TAOR_{k,h}^{m,t} – AQOR_{r3,k,h}^{m,t}))$									
250	10 Minute Spinning Market Reserve Hourly Uplift	$HUSA_h$	9.3.9.1	$\sum_c^{M,T} TD_{k,h,(200)} \times [(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t} + RQ_{k,h}^{m,t}) / \sum_k^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t})]$ Where 'T' is the set of 12 *metering intervals* 't' during *settlement hour* 'h'.	Hourly	Due *IESO*	13	N/A	0	13	May 1, 2002	April 30, 2023	

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				Where $RQ_{k,h}^{m,t}$ is a reallocated quantity whereby *market participant* 'k' is a party to one or more *physical bilateral contracts* for *settlement hour* 'h' in which the *operating reserve* component of *hourly uplift* is to be reallocated between *market participant* 'k' and the other *market participant* that is a party to the contract in which: $RQ_{k,h}^{m,t} = \sum_{s,b} [BCQ_{k,b,h}^{m,t} - BCQ_{s,k,h}^{m,t}]$									
250	10 Minute Spinning Market Reserve Hourly Uplift	$HUSA_h$	9.3.9.1	$\sum_C^{M,T} TD_{k,h,c} \times [(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t} + RQ_{k,h}^{m,t}) / \sum_k^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t})]$ Where: 'C' is the set of the following *charge types* 'c' as follows: **200, 206** Where 'T' is the set of 12 *metering intervals* 't' during *settlement hour* 'h'. Where $RQ_{k,h}^{m,t}$ is a reallocated quantity whereby *market participant*	Hourly	Due *IESO*	13	N/A	0	13	May 1, 2023		Please refer to MR-00467

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				'k' is a party to one or more *physical bilateral contracts* for *settlement hour* 'h' in which the *operating reserve* component of *hourly uplift* is to be reallocated between *market participant* 'k' and the other *market participant* that is a party to the contract in which: $RQ_{k,h}^{m,t} = \sum_{s,b} [BCQ_{k,b,h}^{m,t} - BCQ_{s,k,h}^{m,t}]$									
251	10 Minute Spinning Market Reserve Shortfall Debit	$ORSSD_{k,r,h}$	9.3.8.2	Manual Entry as per 9.3.8.2 where the value below which ORESFk,r,hm,t shall be set at zero equals ∞.	Interval	Due *IESO*	13	13	N/A	N/A			
252	10 Minute Non-spinning Market Reserve Hourly Uplift	$HUSA_h$	9.3.9.1	$\sum_c^{M,T} TD_{k,h,(202)} \times [(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t} + RQ_{k,h}^{m,t}) / \sum_k^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t})]$ Where 'T' is the set of 12 *metering intervals* 't' during *settlement hour* 'h'. Where $RQ_{k,h}^{m,t}$ is a reallocated quantity whereby *market participant* 'k' is a party to one or more *physical bilateral contracts* for *settlement*	Hourly	Due *IESO*	13	N/A	0	13	May 1, 2002	April 30, 2023	

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				hour 'h' in which the *operating reserve* component of *hourly uplift* is to be reallocated between *market participant* 'k' and the other *market participant* that is a party to the contract in which: $RQ_{k,h}^{m,t} = \sum_{s,b} [BCQ_{k,b,h}^{m,t} - BCQ_{s,k,h}^{m,t}]$									
252	10 Minute Non-spinning Market Reserve Hourly Uplift	$HUSA_h$	9.3.9.1	$\sum_C^{M,T} TD_{k,h,c} \times [(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t} + RQ_{k,h}^{m,t}) / \sum_k^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t})]$ Where: 'C' is the set of the following *charge types* 'c' as follows: **202, 208** Where 'T' is the set of 12 *metering intervals* 't' during *settlement hour* 'h'. Where $RQ_{k,h}^{m,t}$ is a reallocated quantity whereby *market participant* 'k' is a party to one or more *physical bilateral contracts* for *settlement hour* 'h' in which the *operating reserve* component of *hourly uplift* is	Hourly	Due *IESO*	13	N/A	0	13	May 1, 2023		Please refer to MR-00467

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				to be reallocated between *market participant* 'k' and the other *market participant* that is a party to the contract in which: $RQ_{k,h}^{m,t} = \sum_{s,b} [BCQ_{k,b,h}^{m,t} - BCQ_{s,k,h}^{m,t}]$									
253	10 Minute Non-spinning Market Reserve Shortfall Debit	$ORSSD_{k,r,h}$	9.3.8.2	Manual Entry as per 9.3.8.2 where the value below which ORESFk,r,hm,t shall be set at zero equals ∞	Interval	Due *IESO*	13	13	N/A	N/A			
254	30 Minute Operating Reserve Market Hourly Uplift	$HUSA_h$	9.3.9.1	$\sum_c^{M,T} TD_{k,h,(204)} \times [(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t} + RQ_{k,h}^{m,t}) / \sum_k^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t})]$ Where 'T' is the set of 12 *metering intervals* 't' during *settlement hour* 'h'. Where $RQ_{k,h}^{m,t}$ is a reallocated quantity whereby *market participant* 'k' is a party to one or more *physical bilateral contracts* for *settlement hour* 'h' in which the *operating reserve* component of *hourly uplift* is to be reallocated between *market participant* 'k' and the other *market*	Hourly	Due *IESO*	13	N/A	0	13	May 1, 2002	April 30, 2023	

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				participant that is a party to the contract in which: $RQ_{k,h}^{m,t} = \sum_{s,b} [BCQ_{k,b,h}^{m,t} - BCQ_{s,k,h}^{m,t}]$									
254	30 Minute Operating Reserve Market Hourly Uplift	$HUSA_h$	9.3.9.1	$\sum_C^{M,T} TD_{k,h,c} \times [(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t} + RQ_{k,h}^{m,t}) / \sum_k^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t})]$ Where: 'C' is the set of the following *charge types* 'c' as follows: **204, 210** Where 'T' is the set of 12 *metering intervals* 't' during *settlement hour* 'h'. Where $RQ_{k,h}^{m,t}$ is a reallocated quantity whereby *market participant* 'k' is a party to one or more *physical bilateral contracts* for *settlement hour* 'h' in which the *operating reserve* component of *hourly uplift* is to be reallocated between *market participant* 'k' and the other *market participant* that is a party to the contract in which:	Hourly	Due *IESO*	13	N/A	0	13	May 1, 2023		Please refer to MR-00467

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				$RQ_{k,h}^{m,t} = \sum_{s,b} [BCQ_{k,b,h}^{m,t} - BCQ_{s,k,h}^{m,t}]$									
255	30 Minute Operating Reserve Market Shortfall Debit	$ORSSD_{k,r,h}$	9.3.8.2	Manual Entry as per 9.3.8.2 where the value below which ORESFk,r,hm,t shall be set at zero equals ∞	Interval	Due *IESO*	13	13	N/A	N/A			
400	Black Start Capability Settlement Credit	N/A	9.4.2.2	Manual Entry as per 9.4.2.2	Monthly	Due MP	13	N/A	N/A	N/A			
404	Regulation Service Settlement Credit	N/A	9.4.2.3	Manual Entry as per 9.4.2.3	Monthly	Due MP	13	N/A	N/A	N/A			
406	Emergency Demand Response Program Credit	N/A	9.4.2.3A	Manual Entry as per 9.4.2.3A	Monthly	Due MP	N/A	N/A	N/A	N/A			EDRP no longer contracted by the *IESO*.
410	*IESO-Controlled Grid* Special Operations Credit	N/A	5.8.2.6	Manual Entry as per 5.8.2.6	Monthly	Either way	13	N/A	N/A	N/A			
450	Black Start Capability Settlement Debit	N/A	9.4.2.2	$= \sum_{H,c}^{M,T} TD_{h,(400)} \times [(AQEW_{k,h}^{m,t} + SQEW_{k,,h}^{i,t}) / \sum_{k,H}^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t})]$	Monthly	Due *IESO*	13	N/A	0	13			

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				Where 'H' is the set of all *settlement hours* 'h' in the month. Where 'T' is the set of all *metering intervals* 't' in the set of all *settlement hours* 'H'.									
451	Hourly Reactive Support and Voltage Control Settlement Debit	N/A	9.4.2.4	$= \sum_{c}^{M,T} TD_{h,c} \times [(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}) / \sum_{k}^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t})]$ Where 'C' is the set of the following charge types 'c' as follows: **1401, 1402, 1404, 1405, 1451** Where 'T' is the set of all *metering intervals* 't' during *settlement hour* 'h'.	Hourly	Due *IESO*	13	N/A	0	13			
452	Monthly Reactive Support and Voltage Control Settlement Debit	N/A	9.4.2.4	$= \sum_{H,C}^{M,T} TD_{h,c} \times [(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}) / \sum_{k,H}^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t})]$ Where 'C' is the set of the following charge types 'c' as follows: **1403, 1406, 1407, 1408, 1409, 1417** Where 'H' is the set of all *settlement hours* 'h' in the month.	Monthly	Due *IESO*	13	N/A	0	13			

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				Where 'T' is the set of all *metering intervals* 't' in the set of all *settlement hours* 'H'.									
454	Regulation Service Settlement Debit	N/A	9.4.2.3	$= \sum_{H,c}{}^{M,T} TD_{h,(404)} \times [(AQEW_{k,h}{}^{m,t} + SQEW_{k,h}{}^{i,t}) / \sum_{k,H}{}^{M,T} (AQEW_{k,h}{}^{m,t} + SQEW_{k,h}{}^{i,t})]$ Where 'H' is the set of all *settlement hours* 'h' in the month. Where 'T' is the set of all *metering intervals* 't' in the set of all *settlement hours* 'H'.	Monthly	Due *IESO*	13	N/A	0	13			
460	*IESO*-Controlled Grid Special Operations Debit	N/A	5.8.2.6	$= \sum_{H,c}{}^{M,T} TD_{h,(410)} \times [(AQEW_{k,h}{}^{m,t} + SQEW_{k,h}{}^{i,t}) / \sum_{k,H}{}^{M,T} (AQEW_{k,h}{}^{m,t} + SQEW_{k,h}{}^{i,t})]$ Where 'H' is the set of all *settlement hours* 'h' in the month. Where 'T' is the set of all *metering intervals* 't' in the set of all *settlement hours* 'H'.	Monthly	Either way	13	N/A	0	13			
500	Must Run Contract Settlement Credit	N/A	9.4.2.1	Manual Entry as per 9.4.2.1	Monthly	Due MP	13	N/A	N/A	N/A			
550	Must Run Contract Settlement Debit	N/A	9.4.2.1	$= \sum_{H,c}{}^{M,T} TD_{h,(500)} \times [(AQEW_{k,h}{}^{m,t}$	Monthly	Due *IESO*	13	N/A	0	13			

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				$(AQEW_{k,h}{}^{m,t} + SQEW_{k,h}{}^{i,t})]$ Where 'H' is the set of all *settlement hours* 'h' in the month. Where 'T' is the set of all *metering intervals* 't' in the set of all *settlement hours* 'H'.									
600	Network Service Credit	N/A	9.4.1 / 9.4.3	$\sum_{k,H,c}(TD_{650})$ Where 'H' is the set of the *settlement hours* 'h' in the month during which the Network Service Demand occurs at every *delivery point* defined for Transmission Network Service charges.	Monthly	Due applicable *transmitters*	13	N/A	N/A	N/A			Subject to the OEB "Ontario Transmission Rate Order".
601	Line Connection Service Credit	N/A	9.4.1 / 9.4.3	$\sum_{k,H,c}(TD_{651})$ Where 'H' is the set of all *settlement hours* 'h' in the month during which the Line Connection Service Demand occurs at every *delivery point* defined for Transmission Line Connection Service charges.	Monthly	Due applicable *transmitters*	13	N/A	N/A	N/A			Subject to the OEB "Ontario Transmission Rate Order".
602	Transformation Connection Service Credit	N/A	9.4.1 / 9.4.3	$\sum_{k,H,c}(TD_{652})$ Where 'H' is the set of all *settlement hours* 'h' in the month during which the Transformation Connection	Monthly	Due applicable *transmitters*	13	N/A	N/A	N/A			Subject to the OEB "Ontario Transmission Rate Order".

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				Demand occurs at every *delivery point* defined for Transmission Transformation Connection Service charges.									
603	Export Transmission Service Credit	N/A	9.4.1 / 9.4.3	$\sum_{k,H,c}(TD_{653}{}^{i})$ Where 'H' is the set of all *settlement hours* 'h' in the month. Where 'i' is an *intertie metering point* 'i' where an export transaction occurred during the month Each *charge type* 603 line detail record line item is therefore totaled on the basis of TD_{653} per *intertie metering point* 'i' per month.	Monthly	Due applicable *transmitter*	13	N/A	N/A	N/A			Subject to the OEB "Ontario Transmission Rate Order".
650	Network Service Charge	N/A	9.4.1 / 9.4.3	$NSD_{k,h}{}^{m} \times$ PTS-N The Billing Demand for Network Transmission Service (kW) is defined as the higher of: Transmission customer coincident peak demand (kW) in the hour of the month when the total hourly demand of all PTS customers is highest for the month; and	Monthly	Due *IESO*	13	N/A	N/A	N/A			Subject to the OEB "Ontario Transmission Rate Order".

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				85% of the customer peak demand in any hour during the peak period.									
651	Line Connection Service Charge	N/A	9.4.1 / 9.4.3	$LCD_{k,h}^{m} \times$ PTS-L Where 'h' is the *settlement hour* of the current *billing period* in which $LCD_{k,h}^{m}$ denotes the non-coincident peak demand for the month.	Monthly	Due *IESO*	13	N/A	N/A	N/A			Subject to the OEB "Ontario Transmission Rate Order".
652	Transformation Connection Service Charge	N/A	9.4.1 / 9.4.3	$TCD_{k,h}^{m} \times$ PTS-T Where 'h' is the *settlement hour* of the current *billing period* in which $TCD_{k,h}^{m}$ denotes the non-coincident peak demand for the month.	Monthly	Due *IESO*	13	N/A	N/A	N/A			Subject to the OEB "Ontario Transmission Rate Order".
653	Export Transmission Service Charge	N/A	9.4.1 / 9.4.3	$\sum_{H}^{T} SQEW_{k,h}^{i,t} \times$ ETS Where 'H' is the set of all *settlement hours* 'h' in the month. Where 'T' is the set of all *metering intervals* 't' during the set of *settlement hours* 'H'.	Monthly	Due *IESO*	13	N/A	0	13			Subject to the OEB "Ontario Transmission Rate Order".
700	Dispute Resolution Settlement Amount	N/A	3.2.7	Manual Entry as per 3.2.7	Monthly	Due MP	13	13	0	13			Note: tax would follow original disputed transaction
702	Debt Retirement Credit	N/A	9.4.6	$\sum_{k,H,c} TD_{752}$	Monthly	Due Ministry of Finance	0	N/A	N/A	N/A			Ontario Regulations

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
													493/01 and 494/01 See Ministry of Energy website for details.
703	Rural and Remote Settlement Credit	N/A	9.4.4	Manual Entry as per Reg	Monthly	Due MP as per Reg	13	N/A	N/A	N/A			Ontario Regulation 442/01 See Ministry of Energy website for details.
704	OPA Administration Credit	N/A	N/A	$\Sigma_K \mathrm{TD}_{\mathrm{k},754}$ Where 'K' is the set of all *market participants* 'k'. Where $\mathrm{TD}_{\mathrm{k},754}$ is the *settlement amount* of *charge type* 754 for the month for *market participant* 'k'.	Monthly	Due *IESO*	13	N/A	N/A	N/A			Implementation details subject to government regulation.
705	Ontario Fair Hydro Plan First Nations On-reserve Delivery Amount	**N/A**	**N/A**	Manual entry based on: (1) the values submitted via on-line settlement form "First Nations On-Reserve Delivery Credit (FNDC)";	Monthly	Due LDCs either way	**13**	**N/A**	**N/A**	**N/A**			Eligibility, rates, and other implementation details subject to government and OEB regulations.
706	Ontario Fair Hydro Plan Distribution Rate Protection Amount	**N/A**	**N/A**	Manual entry based on:	Monthly	Due LDCs either way	**13**	**N/A**	**N/A**	**N/A**			Eligibility, rates, and other implementation details subject to government and OEB regulations.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				(1) the values submitted via on-line settlement form "Distribution Rate Protection (DRP)";									
750	Dispute Resolution Balancing Amount (IESO)	N/A	3.2.7	$\sum_K TD_{k,700}$, where applicable	Monthly	Due *IESO*	N/A	N/A	N/A	N/A			
751	Dispute Resolution Board Service Debit	N/A					13	13	13	13			
752	Debt Retirement Charge	N/A	9.4.6	$AQEW_{k,h}^{m,t} x$ TP Where 'k' is part of a subset of *market participants* meeting the criteria of any government regulation defining the ultimate *consumers* of *energy*.	Monthly	Due *IESO*	13	N/A	N/A	N/A			Ontario Regulations 493/01 and 494/01 See Ministry of Energy website for details.
753	Rural and Remote Settlement Debit	N/A	9.4.4	$AQEW_{k,h}^{m,t} x$ TP	Monthly	Due *IESO*	13	N/A	N/A	N/A			Ontario Regulation 442/01 See Ministry of Energy website for details.
754	OPA Administration Charge	N/A	N/A	$\Sigma_H{}^T AQEW_{k,h}^{m,t} \times$ TP Where 'H' is the set of all *settlement hours* 'h' in the month.	Monthly	Due *IESO*	13	N/A	N/A	N/A			Eligibility, rates, and other implementation details subject to government regulation.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				Where 'T' is the set of all *metering intervals* 't' in *settlement hour* 'h'. Where TP is the rate ($/MWh) for the *OPA* Administration Charge set by *OEB.*									
755	MOE - Ontario Fair Hydro Plan First Nations On-reserve Delivery Balancing Amount	**N/A**	**N/A**	ΣKTDk,705 Where 'K' is the set of all *market participants* 'k'. Where TDk,705 is the total *settlement amount* of *charge type* 705 for the month for *market participant* 'k'.	Monthly	Due Ministry of Energy	**N/A**	**N/A**	**N/A**	**N/A**			Eligibility, rates, and other implementation details subject to government and OEB regulations.
756	MOE - Ontario Fair Hydro Plan Distribution Rate Protection Balancing Amount	**N/A**	**N/A**	ΣKTDk,706 Where 'K' is the set of all *market participants* 'k'. Where TDk,706 is the total *settlement amount* of *charge type* 706 for the month for *market participant* 'k'.	Monthly	Due Ministry of Energy	**N/A**	**N/A**	**N/A**	**N/A**			Eligibility, rates, and other implementation details subject to government and OEB regulations.
850	Market Participant	N/A	2.8.6	Manual Entry as per 2.8.6	Monthly	Due *IESO*	13	13	13	13			

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
	Default Settlement Debit (recovery)												
851	Market Participant Default Interest Debit	N/A	2.8.3, 2.8.5	Manual Entry as per 2.8.3 and 2.8.5	Monthly	Due *IESO*	N/A	N/A	N/A	N/A			
900	GST/HST Credit	N/A	N/A	$\sum_C TD_{k,c}$ A summation of all Goods and Services Tax Credits or Harmonized Sales Tax Credits payable to *market participant* 'k' across all *charge types* 'c'. Where 'C' is the set of all *charge types* 'c'.		Due MP	N/A	N/A	N/A	N/A			Only appear as "SC" record types.
950	GST/HST Debit	N/A	N/A	$\sum_C TD_{k,c}$ A summation of all Goods and Services Tax Debits or Harmonized Sales Tax Debits payable *by market participant* 'k' across all *charge types* 'c'. Where 'C' is the set of all *charge types* 'c'.		Due *IESO*	N/A	N/A	N/A	N/A			Only appear as "SC" record types.
1050	Self-Induced Dispatchable Load CMSC Clawback	N/A	9.3.5.1A	**BUSINESS RULES** are used in conjunction with the definitions below to specify the criteria by which	Interval	Due *IESO*	13	N/A	N/A	N/A			The decision rule for ramping up or down is described in

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				the *IESO* will recover *constrained off* CMSC paid to *dispatchable load* facilities. **Business Rule 1 – Materiality:** *Constrained off* CMSC is allowed for an interval during a *constrained off* event if the total amount of CMSC paid for the trade day to that *dispatchable load* is less than $4000. The daily total includes negative CMSC. ****BUSINESS RULE 1 –** **MATERIALITY THRESHOLD END JUNE 1, 2019** **Business Rule 2 – Non-Dispatchable Portion of Load:** *Constrained off* CMSC is not allowed for an interval during a *constrained off* event if the CMSC is paid for portions of the dispatch where the load has bid greater than or equal to MMCP, indicating that it is a non-dispatchable in that range. [−1OP($EMP_h^{m,t}$, $MQSW_{k,h}^{m,t}$, BL) – MAX (-1OP($EMP_h^{m,t}$, $DQSW_{k,h}^{m,t}$,									Market Manual 5.5: Settlements Part 5.5: Physical Markets Settlement Statements, section 1.6.9.3.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				BL), −1 OP($EMP_h^{m,t}$,$AQEW_{k,h}^{m,t}$, BL)] – [−1OP($EMP_h^{m,t}$, $MQSW_{k,h}^{m,t}$, BL) – MAX (−1OP($EMP_h^{m,t}$, $DQSW_{k,h}^{m,t}$, BL), −1OP ($EMP_h^{m,t}$,$AQEW_{k,h}^{m,t}$, BL), −1OP($EMP_h^{m,t}$,MC_h^m, BL)] Where 'MC' is minimum consumption level and is equal to the quantity in the price quantity pair where the bidding price is MMCP (i.e., $2000). This business rule applies unless CMSC is allowed because of materiality (defined by Business Rule 1). **Business Rule 3 – Dispatch Deviation:** *Constrained off* CMSC is not allowed for an interval during a *constrained off* event if the current 5-minute constrained schedule exceeds the revenue meter value in the previous interval plus 2.5 minutes of ramping. This business rule applies unless CMSC is allowed because of:									

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				Materiality (defined by Business Rule 1); or The load has been *constrained off* economically (defined below – 'Economically *constrained off* interval'); or Operating reserve has been activated (defined below – 'Operating Reserve Activation interval'); or The load is ramping (defined below – 'Ramping interval'); or The load has been manually dispatched down for reliability (defined below – 'Manual Dispatch for Reliability'). **Business Rule 4 – Facility off-line or unable to follow dispatch instructions:** *Constrained off* CMSC is not allowed for an interval during a *constrained off* event if the constrained schedule is 0 MW and the consumption is less than 1 MW, or if the consumption is 0 MW. This business rule applies unless CMSC is allowed because of:									

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				Materiality (defined by Business Rule 1); or The load has been *constrained off* economically (defined below – 'Economically *constrained off* interval'); or Operating reserve has been activated (defined below – 'Operating Reserve Activation interval'); or The load has been manually dispatched down for reliability (defined below – 'Manual Dispatch for Reliability'). In addition to the Business Rules 1 to 4 described above, *constrained off* CMSC is not allowed for hour 'h' if a *dispatchable load* changes its *energy bid* that results in a change in the *facility's market schedule* and the ramping up or down of the *dispatchable load*. **DEFINITIONS** – There are a number of definitions that are used in the specification of criteria for recovery of *constrained off* CMSC									

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				paid to dispatchable load facilities. These are: **Constrained-off event**: A *constrained off* event comprises one or more consecutive intervals where the *market schedule* is greater than the constrained schedule and the *market schedule* is greater than the actual quantity of energy withdrawn. Both conditions must exist to be considered a *constrained off* event. **Economic Constrained–off interval**: A *dispatchable load* is considered to be 'economically *constrained off*' in an interval if the relevant nodal price is greater than or equal to the *bid* price for either the current interval, the next interval or the previous interval. The inequality should be applied to the last MW *constrained off*. **Operating Reserve Activation Interval (ORA)**: A *dispatchable load* is considered to be dispatched in an interval as part of an activation of									

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				operating reserve if one or more of the following conditions exist: The constrained schedule is labeled with the reason code 'ORA'. The interval is 1-3 intervals before an interval with the 'ORA' code. The interval is 1-3 intervals after an interval with the 'ORA' code. **Ramping Interval**: A *generation unit* is considered to be ramping up or ramping down when the unconstrained schedule differs between consecutive hours. A *dispatchable load* is considered to be 'ramping' in an interval if one of the following exist: It is one of the first 3 intervals of the second hour when ramping up. It is one of the last 3 intervals of the first hour when ramping down. **Manual Dispatch for Reliability**: A *dispatchable load* is considered to be a 'manually *constrained off* for reliability' if the *IESO* Control Room logs indicate that the *IESO* needed to									

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				constrain off the load for system or for local requirements.									
1051	Ramp-Down CMSC Claw Back	$RDCB_{k,h}$	9.3.5.1G	$RDCB_{k,h}^{m,t} = -1 \times TD_{k,h,105}^{m,t}$ (See applicable *market manual*)	Interval	Either Way	13	N/A	N/A	N/A			Conditions for the Ramp-Down CMSC Claw Back are described in Market Manual 5: Settlements Part 5.5: Physical Markets Settlement Statements, section 1.6.31.
1101	Real-Time Energy Settlement Amount for Dispatchable Generators	$NEMSC_{k,h}$	9.3.3.2	$EMP_h^{m,t} \times ((AQEI_{k,h}^{m,t} - AQEW_{k,h}^{m,t}) + \sum_{S,B} (BCQ_{s,k,h}^{m,t} - BCQ_{k,b,h}^{m,t}))$	Interval	Either Way	13	N/A	N/A	N/A	May 1, 2023		
1103	Real-Time Energy Settlement Amount for Dispatchable Loads	$NEMSC_{k,h}$	9.3.3.2	$EMP_h^{m,t} \times ((AQEI_{k,h}^{m,t} - AQEW_{k,h}^{m,t}) + \sum_{S,B} (BCQ_{s,k,h}^{m,t} - BCQ_{k,b,h}^{m,t}))$	Interval	Either Way	13	N/A	N/A	N/A	May 1, 2023		
1111	Real-Time Energy Settlement Amount for Imports	$NEMSC_{k,h}$	9.3.3.2	$EMP_h^{m,t} \times (SQEI_{k,h}^{i,t} + \sum_{S,B} (BCQ_{s,k,h}^{m,t} - BCQ_{k,b,h}^{m,t}))$	Interval	Either Way	N/A	13	N/A	N/A	May 1, 2023		

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
1113	Real-Time Energy Settlement Amount for Exports	$NEMSC_{k,h}$	9.3.3.2	$EMP_h^{m,t} \times (((-1) \times SQEW_{k,h}^{i,t}) + \sum_{S,B} (BCQ_{s,k,h}^{m,t} - BCQ_{k,b,h}^{m,t}))$	Interval	Either Way	N/A	N/A	0	13	May 1, 2023		
1114	Real-Time Energy Settlement Amount for Non-Dispatchable Generators	$NEMSC_{k,h}$	9.3	$(HOEP_h \times \sum_T (AQEI_{k,h}^{m,t} - AQEW_{k,h}^{m,t} + \sum_S (BCQ_{s,k,h}^{m,t}))) - (\sum_{B,T} (EMP_h^{m,t} \times BCQ_{b,k,h}^{m,t}))$	Hourly	Either Way	13	N/A	N/A	N/A	May 1, 2023		
1115	Real-Time Energy Settlement Amount for Non-Dispatchable Loads	$NEMSC_{k,h}$	9.3	$(HOEP_h \times \sum_T (AQEI_{k,h}^{m,t} - AQEW_{k,h}^{m,t} + \sum_S (BCQ_{s,k,h}^{m,t}))) - (\sum_{B,T} (EMP_h^{m,t} \times BCQ_{b,k,h}^{m,t}))$	Hourly	Either Way	13	N/A	N/A	N/A	May 1, 2023		
1130	Day-Ahead Intertie Offer Guarantee Settlement Credit	$DA_IOG_{k,h}$	9.3.8A.2A	**<u>**CALCULATIONS FOR *CHARGE TYPE* 1130 END OCTOBER 12, 2011. *CHARGE TYPE* 1130 REPLACED BY *CHARGE TYPE* 1131 EFFECTIVE OCTOBER 13, 2011.**</u> The Day-Ahead Intertie Offer Guarantee *settlement amount* is derived as follows: For all day-ahead import transactions other than those that are subject to a *constrained on event* in the *real-time market:*	Hourly	Due MP	N/A	13	13	13			Subject to IOG OFFSET process under the provisions of 9.3.8A.3 (see also, entry for *charge type* 130 for further details)

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				$\text{MIN}(\text{PDR_DQSI}_{k,h}^{i,t}, \text{DQSI}_{k,h}^{i,t}), \text{PDR_BE}_{k,h}^{i,t}) + \text{TD}_{k,h,105}^{i}]$ Or, in the case of an import transaction subject to a *constrained on event* in the *real-time market:* $\sum^{I} (-1) * \text{MIN}[0, \sum^{T} \text{OP}(\text{EMP}_{h}^{i,t}, \text{MIN}(\text{PDR_DQSI}_{k,h}^{i,t}, \text{DQSI}_{k,h}^{i,t}), \text{PDR_BE}_{k,h}^{i,t}) + \text{OPE}\{\text{adj}\}_{k,h}^{i,t}]$ See 9.3.8A.2A for the definition of the Operating Profit (OP) function referenced above. Where: 'I' is the set of relevant *intertie metering points* 'i'. 'T' is the set of all *metering intervals* 't' during *settlement hour* 'h'. $\text{TD}_{k,h,105}^{i}$ is that component of *charge type* 105 ("Congestion Management Settlement Credit for Energy") applicable to *market participant* 'k' at *intertie metering point* 'i' during *settlement hour* 'h'.									
1131	Intertie Offer Guarantee Settlement Credit	$\text{IOG}_{k,h}$	9.3.8A	The Day-Ahead Intertie Offer Guarantee *settlement amount* is derived as follows:	Hourly	Due MP	N/A	13	N/A	N/A			

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				(DA_IOG_COMP1 + DA_IOG_COMP2 – DA_IOG_COMP3)] Where **DA_IOG_COMP1:** $-1 \times OP(EMP_h^{i,t}, MIN(DA_DQSI_{k,h}^{i,t}, DQSI_{k,h}^{i,t}), DA_BE_{k,h}^{i,t})$ **DA_IOG_COMP2:** $XDA_BE_{k,h}^{i,t} – MAX(0, XBE_{k,h}^{i,t})$ **DA_IOG_COMP3:** Component 3 is calculated when: the CMSC for energy ($TD_{k,h,105}^{m,t}$) for the same metering interval is a value other than zero. For Component 3 (DA_IOG_COMP3), the six scenarios of the possible orderings of the generator's DA_DQSI, DQSI and MQSI are as follows: 1. DQSI >= MQSI >= DA_DQSI 2. MQSI >= DQSI >= DA_DQSI 3. DQSI > DA_DQSI > MQSI 4. MQSI > DA_DQSI > DQSI 5. DA_DQSI >= DQSI > MQSI 6. DA_DQSI >= MQSI > DQSI Scenario 1 and 2:									

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				0 Scenario 3: $OP(EMP_h^{i,t}, MQSI_{k,h}^{i,t}, BE) – OP(EMP_h^{i,t}, DA_DQSI_{k,h}^{i,t}, BE)$ Scenario 4: $OP(EMP_h^{i,t}, DA_DQSI_{k,h}^{i,t}, BE) – OP(EMP_h^{i,t}, DQSI_{k,h}^{i,t}, BE)$ Scenario 5 and 6: $TD_{k,h,105}^{m,t}$ Where 'I' is the set of relevant *intertie metering points* 'i'. 'T' is the set of all *metering intervals* 't' during *settlement hour* 'h'. 'OP' is the operating profit function defined in *IESO market rules* Section 9.3.8A.2. $XDA_BE_{k,h}^{i,t} = (−1) * [OP(EMP_h^{i,t}, DA_DQSI_{k,h}^{m,t}, DA_BE) – OP(EMP_h^{i,t}, min(DA_DQSI_{k,h}^{m,t}, DQSI_{k,h}^{m,t}, DA_BE)]$ $XBE_{k,h}^{i,t} = (−1) * [OP(EMP_h^{i,t}, DA_DQSI_{k,h}^{i,t}, BE) – OP(EMP_h^{i,t}, min(DA_DQSI_{k,h}^{i,t}, DQSI_{k,h}^{i,t}, BE)]$ Where $EMP_h^{i,t} = 0$ The Intertie Offer Guarantee *settlement amount* is derived from an hourly *Energy* Import sub component ($EIM_{k,h}$) as follows:									

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				$RT\text{-}IOG_{k,h} = EIM_{k,h}$ The Real-Time Intertie Offer Guarantee ($RT\text{-}IOG_{k,h}$) *settlement amount* is derived as follows: $\sum_I (-1)*\text{MIN}[0,\sum^T \text{OP}(\text{EMP}_h^{i,t}, \text{MQSI}_{k,}$ Where 'I' is the set of relevant *intertie metering points* 'i'. 'T' is the set of all *metering intervals* 't' during *settlement hour* 'h'. 'OP' is the operating profit function defined in *IESO market rules* Section 9.3.8A.2. The IOG_OFFSET component of this *charge type* is calculated as follows: **The Day-Ahead IOG rate:** DA_IOG_RATE = IF [DA_IOG is not NULL, DA_IOG / min(DA_DQSI, DQSI), 0] **The Real-Time IOG rate:** RT_IOG_RATE = IF[RT_IOG is NULL, 0, RT_IOG/DQSI] **The matrix is arranged in ascending order on DA_IOG_RATE and the day-ahead import quantities are offset against the day-ahead export schedule quantities:**									

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				DA_DQSW_REM = [MAX[0, DA_OFFSET_DQSW)]] DA_OFFSET_DQSW = MIN[DA_DQSI, DQSI, DA_DQSW_REM] **The day-ahead IOG offset flag:** DA_OFFSET_FLAG = IF(DA_OFFSET_DQSW > [50% × MIN(DA_DQSI,DQIS)],Y,N) **The IOG offset rate:** IOG_SETTLEMENT_RATE = IF[DA_OFFSET_FLAG = 'Y', RT_IOG_RATE, MAX(RT_IOG_RATE, DA_IOG_RATE)] Subject to: MI[n,9] >= MIN[n−1,9] MI[1,9] = MIN[MI[1 to N,9]] MI[1 to N,9] <> 0 **The Gross IOG amount:** IOG = IOG dollar amount associated with the used to calculate IOG_SETTLEMENT_RATE **The matrix is arranged in ascending order on IOG_SETTLEMENT_RATE and the real-time import quantities are offset against the real-time export schedule quantities:** RT_DQSW_REM = [MAX[0, DQSW – RT_OFFSET_DQSW)]]								

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				RT_OFFSET_DQSW = MIN[DQSI, RT_DQSW_REM] **The IOG offset settlement amount:** IOG_OFFSET = (IOG_SETTLEMENT_RATE * RT_OFFSET_DQSW) **The IOG settlement amount:** NET_IOG = (IOG – IOG_OFFSET)									
1133	Day-Ahead Generation Cost Guarantee Payment	$DA_GCG_{k,h}$	9.4.7D	**<u>CALCULATIONS FOR *CHARGE TYPE* 1133 END OCTOBER 12, 2011.</u>** <u>Dispatchable *delivery points:*</u> $MAX[0, (DA_CGC + DA_COST - \sum^{T} EMP_{h}^{m,t} \times AQEI\{limited\}_{k,h}^{m,t} - \sum^{T} CMSC\ REV_{k,h,}^{m,t}]$ **Subject to:** $AQEI\{limited\}_{k,h}^{m,t} = MIN[AQEI_{k,h}^{m,t}$, *minimum loading point*] Where 'DA_CGC' is a Day-Ahead *Combined Guaranteed Costs* variable, assessed in accordance with the applicable *market manual* (see	Hourly	Due MP	13	N/A	N/A	N/A			

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				also Section 2.1 "Variable Description"). Where 'm' is *delivery point* 'm' at which the *generation unit* incurring the relevant costs is located. Where 'T' is a set of *metering intervals* 't' from a valid start time to the end of *minimum generation block run-time.* Where $AQEI\{limited\}_{k,h}^{m,t}$ shall denote all allocated quantities in MWh of *energy* injected at *delivery point* 'm' irrespective of any submission of *physical allocation data* by *market participant* 'k' in metering interval 't' of *settlement* hour 'h' up to the *generation unit's minimum loading point.* Where DA_COST is fuel and O&M cost component related to operation of the *generation unit* at its *minimum loading point* during its *minimum generation block run-time* (these costs are calculated based on the *offer* price associated with Pre-dispatch of record).									

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				$DA_COST_k = \sum^{T^*_{H2}} COST(AQEI\{limited\}_{k,h}^{m,t}, PDR_BE_{k,h}^{m,t})$ A. Where the COST function is defined as follows: $COST(Q,B) = \sum_{i=1}^{s^*} P_i \cdot (Q_i - Q_{i-1})$ *where:* • B is the n × 2 matrix (B) of offered *price-quantity pairs* (P_i , Q_i) • s* is the highest indexed row of B such that $Q_{s*-1} \leq Q \leq Q_{s*}$ and where $Q_0=0$ B. Where H2 is the set of all *settlement hours* 'h' during the period from the *Pre-dispatch of Record* 'start hour' until the end of *minimum generation block run* C. Where 'T*' is the set of metering intervals 't' in the set of all settlement hours 'H2' Where $CMSC_REV_{k,h}^{m,t}$ is any real-time $CMSC(TD_{k,h,105}^{m,t})$ payment									

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				associated with allocated quantities in MWh of *energy* injected at *delivery point* 'm' irrespective of any submission of *physical allocation data* by *market participant* 'k' in metering interval 't' of *settlement* hour 'h' up to the *generation unit's minimum loading point.* CMSC_REV is calculated using the following rules: 1) Real-time CMSC ($TD_{k,h,105}^{m,t}$) for the same interval is greater than zero. 2) If $MQSI_{k,h}^{m,t}$ and max($DQSI_{k,h}^{m,t}$,$AQEI_{k,h}^{m,t}$) >= MLP, then $CMSC_REV_{k,h}^{m,t} = 0$. 3) In the case of a *constrained-off event*: a. If $MQSI_{k,h}^{m,t}$ < MLP, then $CMSC_REV_{k,h}^{m,t} = TD_{k,h,105}^{m,t}$ b. If $MQSI_{k,h}^{m,t}$ >= MLP and max($DQSI_{k,h}^{m,t}$,$AQEI_{k,h}^{m,t}$) <= MLP, then $CMSC_REV_{k,h}^{m,t} = OP(EMP_{h}^{m,t},MLP,BE) – OP(EMP,max(DQSI_{k,h}^{m,t},AQEI_{k,h}^{m,t}),BE)$.									

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				4) In the case of a *constrained-on event*: a. If $MQSI_{k,h}^{m,t} < MLP$ and $\min(DQSI_{k,h}^{m,t}, AQEI_{k,h}^{m,t}) < MLP$, then $CMSC_REV_{k,h}^{m,t} = TD_{k,h,105}^{m,t}$ b. If $MQSI_{k,h}^{m,t} <= MLP$ and $\min(DQSI_{k,h}^{m,t}, AQEI_{k,h}^{m,t}) >= MLP$, then $CMSC_REV_{k,h}^{m,t} = OP(EMP_{h}^{m,t}, MQSI_{k,h}^{m,t}, BE) - OP(EMP_{h}^{m,t}, MLP, BE)$ (See applicable *market manual*)									
1134	Day-Ahead Linked Wheel Failure Charge	$DA_LWFC_{k,h}$	9.3.8E	$MAX[(-1) * [(DA_LWSDk,hi) * MAX[0,(DA_PSk,hi - PD_PSk,hi)]], (RT_IFC_DALWk,hi + RT_EFC_DALWk,hi)]$ Where: $DA_LWSDk,hi,t = MAX[MAX (DA_DQSIk,hi,t - PD_DQSIk,hi,t, DA_DQSWk,hi,t - PD_DQSWk,hi,t),0]$	Hourly	Due *IESO*	N/A	13	13	13			

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				$\left(\begin{matrix}\mathrm{EMP}_{\mathrm{hm,t}}+\\ \mathrm{PB_IM}_{\mathrm{ht}}-\mathrm{PD_EMP}_{\mathrm{hm,t}}\end{matrix}\right)$ * MAX $\left(\begin{matrix}\mathrm{DA_DQSI}_{\mathrm{k,hi,t}}-\mathrm{PD_DQSI}_{\mathrm{k,hi,t}},\\ 0\end{matrix}\right)\Bigg]$, $\left(\begin{matrix}\mathrm{MAX}(0,\mathrm{EMP}_{\mathrm{hm,t}})\\ * \mathrm{MAX}\left(\begin{matrix}\mathrm{DA_DQSI}_{\mathrm{k,hi,t}}-\\ \mathrm{PD_DQSI}_{\mathrm{k,hi,t}},0\end{matrix}\right)\end{matrix}\right)\Bigg]$_EFC_D $\sum_{\mathrm{I,T}}(-1)$ * MIN MAX[0, $\left(\begin{matrix}\mathrm{PD_EMP}_{\mathrm{hm,t}}-\\ \mathrm{EMP}_{\mathrm{hm,t}}-\mathrm{PB_EX}_{\mathrm{ht}}\end{matrix}\right)$ * MAX $\left(\begin{matrix}\mathrm{DA_DQSW}_{\mathrm{k,hi,t}}-\\ \mathrm{PD_DQSW}_{\mathrm{k,hi,t,}}\ 0\end{matrix}\right)\Bigg]$, $\Bigg($MAX(0, PD_EM * MAX $\left(\begin{matrix}\mathrm{DA_DQ}\\ \mathrm{PD_DQ}\end{matrix}\right)$ Where: 'T' is the set of 12 metering intervals 't' during settlement hour 'h'. 'I' is the set of all intertie metering points 'i'.									
1135	Day-Ahead Import Failure Charge	$\mathrm{DA_IFC}_{\mathrm{k,h}}$	9.3.8B	$\sum^{\mathrm{I,T}}(-1)$ * MINMAX[0, OP($\mathrm{PD_EMP_h}^{\mathrm{m,t}}$, $\mathrm{DA_DQSI_{k,h}}^{\mathrm{i,t}}$, $\mathrm{DA_BE_{k,k}}^{\mathrm{i,t}}$) –	Hourly	Due *IESO*	N/A	13	N/A	N/A			Subject to exemptions under the provisions of 9.3.8B.1.2

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				$OP(PD_EMP_h^{m,t}, PD_DQSI_{k,h}^{i,t}, DA_BE_{k,k}^{i,t})]$, $(MAX(0, XPD_BE_{k,h}^{i,t} – XDA_BE_{k,h}^{i,t})]$, $(MAX(0, PD_EMP_h^{m,t})* DA_ISD_{k,h}^{i,t})]$ Where: 'OP' is the operating profit function defined in *IESO market rules* Section 9.3.8B.2. 'T' is the set of all *metering intervals* 't' in *settlement hour* 'h'. 'I' is the set of all *intertie metering points* 'i'. $DA_ISD_{k,h}^{i,t} = MAX (DA_DQSI_{k,h}^{i,t} – PD_DQSI_{k,h}^{i,t}, 0)$ $XDA_BE_{k,h}^{i,t} = (−1) * [OP(0,DA_DQSI,DA_BE) −OP(0,PD_DQSI,DA_BE)]$ $XPD_BE_{k,h}^{i,t} = (−1) * [OP(0,DA_DQSI,PD_BE) − OP(0,PD_DQSI,PD_BE)]$									
1136	Day-Ahead Export Failure Charge	$DA_EFC_{k,h}$	9.3.8D	$\sum^{I,T}(−1) * MINMAX[0,(−1) * OP(PD_EMP_h^{m,t}, DA_DQSW_{k,h}^{i,t}, DA_BL_{k,k}^{i,t}) – (−1)*$	Hourly	Due *IESO*	N/A	N/A	0	13			

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				$OP(PD_EMP_h^{m,t}, PD_DQSW_{k,h}^{i,t}, DA_BL_{k,k}^{i,t})]$, $(MAX(0, XDA_BL_{k,h}^{i,t} - XPD_BL_{k,h}^{i,t}), (MAX(0, XDA_BL_{k,h}^{i,t})]$ Where: 'OP' is the operating profit function defined in *IESO market rules* Section 9.3.8B.2. 'T' is the set of all *metering intervals* 't' in *settlement hour* 'h'. 'I' is the set of all *intertie metering points* 'i'. $XDA_BL_{k,h}^{i,t}$ = [OP(0,DA_DQSW,DA_BL) −OP(0,PD_DQSW,DA_BL)] $XPD_BL_{k,h}^{i,t}$ = [OP(0,DA_DQSW,PD_BL) − OP(0,PD_DQSW,PD_BL)]									
1137	Intertie Offer Guarantee Reversal	**Context 1:** $IOG_REV_{k,h}$ **Context 2:** $DA_IOG\{adj\}_{k,h}^{i}$	9.3.8A.1.2 and 9.3.8A.7 to 9.3.8A.9	****CALCULATIONS FOR *CHARGE TYPE* 1137 END OCTOBER 12, 2011.** **NOTE**: This *charge type* is used in two separate contexts as follows: **Context 1:** When a day-ahead Intertie Offer Guarantee and a real-time Intertie Offer Guarantee apply to the same import transaction, the lower of the two is reversed by this *charge type*.	**Context 1:** Hourly **Context 2:** Hourly, but reported on the last *trading day* of the *billing period*	**Context 1:** Due *IESO* **Context 2:** Due MP	N/A	13	13	13			**Note:** Context 1 and Context 2 can both be applied to the same import.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				$-1 \times TD_{k,h,c}^{i}$ Where: 'c' is *charge type* 130 or 1130 as the case may be such that: $TD_{k,h,c}^{i} = MIN (TD_{k,h,130}^{i}, TD_{k,h,1130}^{i})$ **Context 2:** In cases where this *charge type* is used for the purposes of applying the intertie offer guarantee adjustment ($DA_IOG\{adj\}_{k,h}^{i}$), the *settlement amount* applied is $DA_IOG\{adj\}_{k,h}^{i}$ and is calculated as follows: $DA_IOG\{adj\}_{k,h}^{i} = MAX [0 , IOG_FV_{k,h}^{i} – TD_{k,h,100}^{i} – MAX(TD_{k,h,1130}^{i}, TD_{k,h,130}^{i}) – TD_{k,h,105}^{i}]$ Where: $TD_{k,h,100}^{i}$, $TD_{k,h,1130}^{i}$, $TD_{k,h,130}^{i}$ and $TD_{k,h,105}^{i}$ are the *settlement amounts* for *charge types* 100, 1130, 130 and 105 respectively, that are applicable to *market participant* 'k' during *settlement hour* 'h' at *intertie metering point* 'i'.									
1138	Day-Ahead Fuel Cost Compensation Credit	$DA_FCC_{k,h}$	9.4.7E	Manual entry as per 9.4.7E.2	Hourly	Due MP	13	N/A	N/A	N/A			
1139	Intertie Failure Charge Reversal	$IFC_REV_{k,h}$	9.3.8C.6	**<u>**CALCULATIONS FOR *CHARGE TYPE* 1139 END OCTOBER 12, 2011.</u>	Hourly	Due *IESO*	N/A	13	N/A	N/A			

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				When a Day-Ahead Import Failure Charge and a Real-time Import Failure Charge apply to the same import transaction, the lower of the two is reversed by this *charge type*. $-1 \times TD_{k,h,c}{}^{i}$ Where: 'c' is *charge type* 135 or 1135 as the case may be such that: $TD_{k,h,c}{}^{i} = MIN(-1 \times TD_{k,h,135}{}^{i}, -1 * TD_{k,h,1135}{}^{i})$									
1142	Ontario Fair Hydro Plan Eligible RPP Consumer Discount Settlement Amount	**N/A**	**N/A**	***** CHARGE TYPE* 1142 REPLACED BY *CHARGE TYPE* 142 EFFECTIVE NOVEMBER 1, 2019 ***** Manual entry based on: (1) the values submitted via on-line settlement forms "Regulated Price Plan vs. Market Price – Variance for Conventional Meters", "Regulated Price Plan vs. Market Price – Variance for Smart Meters" and "Regulated	Monthly	Due LDCs, Unit Sub-Meter Providers and eligible MPs either way	**13**	**N/A**	**N/A**	**N/A**			Eligibility, rates, and other implementation details subject to government and OEB regulations.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				Price Plan – Final Variance Settlement Amount"; or (2) For eligible *IESO market participant consumers:* NEMSCk,H – { MIN [TLQ , ΣH M,T (AQEWk,hm,t – AQEIk,hm,t − Σs BCQs,k,hm,t)] × RPPl=1 + MAX [0, ΣH M,T (AQEWk,hm,t – AQEIk,hm,t − Σs BCQs,k,hm,t) – TLQ] × RPPl=2 }									
1143	Ontario Fair Hydro Plan Eligible Non-RPP Consumer Discount Settlement Amount	**N/A**	**N/A**	Manual entry based on: (1) the values submitted via on-line settlement form "Ontario Fair Hydro Plan (OFHP) for Eligible Non-RPP Customers";	Monthly	Due LDCs, Unit Sub-Meter Providers and eligible MPs either way	**13**	**N/A**	**N/A**	**N/A**			Eligibility, rates, and other implementation details subject to government and OEB regulations.
1144	Ontario Fair Hydro Plan Financing Entity Amount	**N/A**	**N/A**	Manual entry based on: (1) the values submitted via on-line settlement form "Ontario Fair Hydro Plan – Financing Entity Funding Expenses";	Monthly	Due Financing Entity	**N/A**	**N/A**	**N/A**	**N/A**			Implementation details subject to government regulations

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
1145	Ontario Fair Hydro Plan Financing Entity Interest	**N/A**	**N/A**	Manual entry based on: (1) the values submitted via on-line settlement form "Ontario Fair Hydro Plan – Financing Entity Funding Expenses";	Monthly	Due Financing Entity	**N/A**	**N/A**	**N/A**	**N/A**			Implementation details subject to government regulations
1148	GA Energy Storage Injection Reimbursement	N/A	N/A	Uk × GARB	Monthly	Due MP	13	N/A	N/A	N/A			Eligibility and other implementation details subject to government regulation.
1188	Day-Ahead Fuel Cost Compensation Debit	DA_FCC_Uk,h	9.4.8.1.12	$= \sum_{K,H,c\ M,T} TD_c \times \left[\frac{\left(AQEW_{k,hm,t} + SQEW_{k,hi,t}\right)}{\sum_{K,HM,T}\left(AQEW_{k,hm,t} + SQEW_{k,hi,t}\right)}\right]$ Where: 'c' is charge type 1138. 'K' is the set of all market participants 'k'. 'M' is the set of all delivery points 'm' and intertie metering points 'i'. 'H' is the set of all settlement hours 'h' in the month.	Monthly	Due IESO	13	N/A	0	13			

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				'T' is the set of all metering intervals 't' in the set of all settlement hours 'H'.									
1192	Ontario Fair Hydro Plan Eligible RPP Consumer Discount Balancing Amount	N/A	N/A	***** CHARGE TYPE 1192 REPLACED BY CHARGE TYPE 192 EFFECTIVE NOVEMBER 1, 2019 ***** ΣKTDk,1142 Where 'K' is the set of all market participants 'k'. Where TDk,1142 is the total settlement amount of charge type 1142 for the month for market participant 'k'.	Monthly	Due IESO	N/A	N/A	N/A	N/A			Eligibility, rates, and other implementation details subject to government and OEB regulations.
1193	Ontario Fair Hydro Plan Eligible Non-RPP Consumer Discount Balancing Amount	**N/A**	**N/A**	ΣKTDk,1143 Where 'K' is the set of all *market participants* 'k'. Where TDk,1143 is the total *settlement amount* of *charge type* 1143 for the month for *market participant* 'k'.	Monthly	Due *IESO*	**N/A**	**N/A**	**N/A**	**N/A**			Eligibility, rates, and other implementation details subject to government and OEB regulations.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
1194	Ontario Fair Hydro Plan Financing Entity Balancing Amount	**N/A**	**N/A**	ΣKTDk,1144 Where 'K' is the set of all *market participants* 'k'. Where TDk,1144 is the total *settlement amount* of *charge type* 1144 for the month for *market participant* 'k'.	Monthly	Due IESO	**N/A**	**N/A**	**N/A**	**N/A**			Implementation details subject to government regulations
1195	Ontario Fair Hydro Plan Financing Entity Balancing Interest	**N/A**	**N/A**	ΣKTDk,1145 Where 'K' is the set of all *market participants* 'k'. Where TDk,1145 is the total *settlement amount* of *charge type* 1145 for the month for *market participant* 'k'.	Monthly	Due IESO	**N/A**	**N/A**	**N/A**	**N/A**			Implementation details subject to government regulations
1300	Capacity Based Demand Response Program Availability Payment	N/A	N/A	****CALCULATIONS FOR *CHARGE TYPE* 1300 ENDED ON OCTOBER, 2018.** $= HA_H \times MCMW_h \times AAR$	Monthly	Due MP	13	N/A	N/A	N/A			

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
	Settlement Amount			Where: 'AAR' means 'Adjusted Availability Rate'. 'H' is the total hours a DRMP is available in a program month. 'HA' means 'Hours of Availability'. 'MCMW' means 'Monthly Contracted MW'.									
1301	Capacity Based Demand Response Program Availability Over-Delivery Settlement Amt	N/A	N/A	**<u>CALCULATIONS FOR *CHARGE TYPE* 1301 ENDED ON OCTOBER, 2018.</u> $= \sum_H (\mathrm{CMW}_h - \mathrm{MCMW}_h) \times \mathrm{AODR}_h$ Applicable only in response to an 'Open Standby Notification'. Where: 'AODR' means 'Availability Over-Delivery Rate'. 'CMW' means 'Confirmed MW'. 'H' is the set of all hours 'h' in the month where the 'CMW' exceeded the 'MCMW'. 'MCMW' means 'Monthly Contracted MW'.	Monthly	Due MP	13	N/A	N/A	N/A			

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
1302	Capacity Based Demand Response Program Availability Set-Off Settlement Amount	N/A	N/A	**<u>**CALCULATIONS FOR *CHARGE TYPE* 1302 ENDED ON OCTOBER, 2018.</u>** The charge to a DRMP is highest of **A**, **B** or **C:** **A: Availability Set-Off (Reliability)** $= \sum_H \text{PSO}_h \times \text{AAR} \times \text{MCMW}_h$ This formula applies when the Reliability Rate for a given Demand Response Account is less than 85% during any interval of an Activation Hour, or where the Participant is not Fully Available for Curtailment. Where: 'AAR' and 'MCMW' have the same meaning as in CT1300. 'H' is the set of all activation hours 'h' for the activation period. 'PSO' means 'Performance Set-Off Factor' as described in the market manual. **B: Availability Set-Off (Timely Confirmation)** $= \text{PSO} \times \text{AAR} \times \text{MCMW}_h \times \text{CDP}$	Monthly	Due IESO	13	N/A	N/A	N/A			

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				This formula applies when the Participant, regardless of Activation, has failed to deliver, or delivers late, a Confirmation that is required by the *IESO*. Where: 'AAR' and 'MCMW' have the same meaning as in CT1300. 'CDP' (Contracted Dispatch Period) means four consecutive hours. Each Contracted Dispatch Period shall occur within the hours of Availability, and shall occur within and no more than once in accordance with the Daily Schedule. 'PSO' has the same meaning as defined above. **C: Availability Set-Off (Low Confirmation)** $= \sum_H (\text{PSO} \times \text{AAR} \times (\text{MCMW}_h - \text{CMW})$ This formula applies when the Confirmed MW's are less than 95% of the Monthly Contracted MW for a Confirmed Hour of the Contracted Dispatch Period. Where:									

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				'AAR' and 'MCMW' have the same meaning as in CT1300. 'CMW' has the same meaning as in CT1301. 'H' is the set of all confirmed hours 'h' when the Confirmed MW's are less than 95% of the Monthly Contracted MW for the Contracted Dispatch Period. 'PSO' has the same meaning as defined above.									
1303	Capacity Based Demand Response Program Utilization Payment Settlement Amount	N/A	N/A	**<u>CALCULATIONS FOR *CHARGE TYPE* 1303 ENDED ON OCTOBER, 2018.</u>** $= [\sum_H (\mathrm{AAM}_h \times \mathrm{UR}_h)] - [\sum_H (\mathrm{NG}_h \mathrm{x}\ \mathrm{MIN}(\mathrm{HOEP}, \mathrm{UR}_h))]$ Where: 'AAM' (Actual Activated MWh), means the number of MWh Curtailed by a Participant when requested by the *IESO*, as measured through the use of electricity meter(s). Curtailment shall not exceed the product of the Activation MW and the activation period requested by the *IESO*, plus the lesser of an additional 15% of the Activation MW per hour of the activation period, OR 15 MWh per hour of the activation period.	Monthly	Due MP	13	N/A	N/A	N/A			

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				'H' is the total hours 'h' a DRMP is activated in a program month. 'HOEP' means Hourly Ontario Energy Price. 'NG' (Net Generation), means the MWh of net electricity generated by any contributor that is a behind the meter generator. 'UR' (Utilization Rate), means the rates, expressed in $/MWh, as specified in the Demand Response Schedule.									
1304	Capacity Based Demand Response Program Utilization Set-Off Settlement Amount	N/A	N/A	**<u>CALCULATIONS FOR *CHARGE TYPE* 1304 ENDED ON OCTOBER, 2018.</u>** The charge to a DRMP is highest of **A**, **B** or **C:** **A: Utilization Set-Off (Reliability)** $= \sum_H \mathrm{PSO}_h \times \mathrm{UR} \times \mathrm{MCMW}_h$ This formula applies when the Reliability Rate for a given Demand Response Account is less than 85% during any interval of an Activation Hour. Where: 'H' is the set of all activation hours 'h' for the activation period.	Monthly	Due IESO	13	N/A	N/A	N/A			

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				'PSO' has the same meaning as in CT 1301. 'UR' has the same meaning as in CT1303. 'MCMW' has the same meaning as in CT1300. **B: Utilization Set-Off (Timely Confirmation)** $= PSO \times UR \times MCMW_h \times CDP$ This formula applies when the DRMP, regardless of Activation, has failed to deliver, or delivers late, a Confirmation that is required by the *IESO*. Where: 'CDP' (Contracted Dispatch Period) means four consecutive hours. Each Contracted Dispatch Period shall occur within the hours of Availability, and shall occur within and no more than once in accordance with the Daily Schedule. 'MCMW' has the same meaning as defined above. 'PSO' has the same meaning as defined above. 'UR' has the same meaning as defined above.									

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				C: Utilization Set-Off (Low Confirmation) $= \sum_H (\text{PSO} \times \text{UR} \times (\text{MCMW}_h - \text{CMW})$ This formula applies when the Confirmed MW's are less than 95% of the Monthly Contracted MW for a Confirmed Hour of the Contracted Dispatch Period. Where: 'CMW' has the same meaning as in CT1301. 'H' is the set of all confirmed hours 'h' when the Confirmed MW's are less than 95% of the Monthly Contracted MW for the Contracted Dispatch Period. 'MCMW' has the same meaning as defined above. 'PSO' has the same meaning as defined above. 'UR' has the same meaning as defined above.									
1305	Capacity Based Demand Response Program Planned Non-Performance Event Set-Off Amt	N/A	N/A	**<u>**CALCULATIONS FOR *CHARGE TYPE* 1305 ENDED ON OCTOBER, 2018.**</u> The Planned Non-Performance Availability Set-Off applies for any day for which a participant has requested a Non-Performance Event as part of either a Single Day Non-	Monthly	Due IESO	13	N/A	N/A	N/A			

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				Performance Event or a part of an Extended Period Planned Non-Performance Event. The monthly set-off calculation is the sum of all: 1. Non-Activation Day Non-Performance Availability Set-Offs and 2. Activation Day Non-Performance Availability Set-Offs. For 1.) The Non-Activation Day Non-Performance Availability Set-Off amount is: $= (AAR \times MCMW_h \times HANE_H)$ Where: 'AAR' has the same meaning as in CT1300. 'HANE' (Hours of Availability for a Non-Performance Event), represents the Hours of Availability for all days in the contract month for which a planned Non-Performance Event is requested and for which an Activation Notice is not received by the participant.									

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				'MCMW' has the same meaning as in CT1300. For 2.) The Activation Day Non-Performance Availability Set-Off amount is: = (OH × AAR × $MCMW_h$ × $NEWF_H$) Where: 'AAR' and 'MCMW' have the same meaning as in CT1300. 'OH' (Opportunity Hours), means 64 if Option A is applicable to the Demand Response Account; or 32 if Option B is applicable to the Demand Response Account. 'NEWF' (Non-Performance Event Weighting Factor), means 10%, unless the Actual Activated MWh per interval, as averaged over all of the Intervals in the Contracted Dispatch Period for the Activation, is greater than or equal to the product of the Monthly Contracted MW and 1/12 of an hour in which case 'NEWF' means 50%.									
1306	Capacity Based Demand Response Program Measurement Data Set-Off Settlement Amt	N/A	N/A	**<u>**CALCULATIONS FOR *CHARGE TYPE* 1306 ENDED ON OCTOBER, 2018.**</u> = MDSF × (HA_H × $MCMW_h$ × AAR)	Monthly	Due IESO	13	N/A	N/A	N/A			

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				This formula applies when the complete set of weekly measurement data for a Demand Response Account are not received as per the CBDR Processing Timelines. The formula recovers a percentage of the availability payment for the applicable week. Where: 'MDSF' (Measurement Data Set-Off Factor), is an increasing factor for every week that the full data remains undelivered. The factor is equal to: • 20% for the first week that the full data remains undelivered; • 33% for the second week that the full data remains undelivered; • 50% for the third week that the full data remains undelivered; and • 100% for the fourth week that the full data remains undelivered. 'AAR', 'HA' and 'MCMW' have the same meaning as in CT1300. 'H' is the total hours a DRMP is available for the applicable week.									
1307	Capacity Based Demand Response Program Buy-	N/A	N/A	**<u>**CALCULATIONS FOR *CHARGE TYPE* 1307 ENDED ON OCTOBER, 2018.**</u>	Monthly	Due IESO	13	N/A	N/A	N/A			

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
	Down Settlement Amount			Buy-Down means the act by the DRMP chooses to reduce its Monthly Contracted MW and/or remove up to three Daily Schedules from participation in CBDR. For the Buy-Down of Monthly Contracted MW the payment is: = (MCMWR × BDR × HAE) Where: 'MCMWR' (Monthly Contracted MW Reduction), means the MW of demand reduction in the Monthly Contracted MWs. 'BDR' (Buy-Down Rate), means the Buy-Down Rate, expressed in $/MW. 'HAE' (Hours of Availability Elapsed), means the number of Hours of Availability that have elapsed in the Schedule Term up to the date that the reduction takes effect. For the Buy-Down of the Daily Schedules the payment is: = (MCMW × RD × BDR × HAE) Where: 'BDR' has the same meaning as defined above.									

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				'HAE' has the same meaning as defined above. 'MCMW' has the same meaning as in CT1300. 'RD' (Requested Days), means the number of Business Days per week from which the Hours of Availability are to be removed.									
1308	Capacity Based Demand Response Program Performance Breach Settlement Amount	N/A	N/A	**CALCULATIONS FOR *CHARGE TYPE* 1308 ENDED ON OCTOBER, 2018. Performance breach amounts are calculated as defined in the market manual.	Monthly	Either way	13	N/A	N/A	N/A			
1309	Demand Response Pilot – Availability Payment	N/A	N/A	**CALCULATIONS FOR *CHARGE TYPE* 1309 ENDED ON APRIL, 2018. Calculated as per demand response pilot contracts.	Monthly	Due MP	13	N/A	N/A	N/A			Demand Response Pilot
1310	Demand Response Pilot – Availability Clawback	N/A	N/A	**CALCULATIONS FOR *CHARGE TYPE* 1310 ENDED ON APRIL, 2018. Calculated as per demand response pilot contracts.	Hourly	Due IESO	13	N/A	N/A	N/A			Demand Response Pilot

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
1311	Demand Response Pilot – Availability Charge	N/A	N/A	**<u>**CALCULATIONS FOR *CHARGE TYPE* 1311 ENDED ON APRIL, 2018.**</u> Calculated as per demand response pilot contracts.	Monthly	Due IESO	13	N/A	N/A	N/A			Demand Response Pilot
1312	Demand Response Pilot – Availability Adjustment	N/A	N/A	**<u>**CALCULATIONS FOR *CHARGE TYPE* 1312 ENDED ON APRIL, 2018.**</u> Calculated as per demand response pilot contracts.	Monthly	Due IESO	13	N/A	N/A	N/A			Demand Response Pilot
1313	Demand Response Pilot – Demand Response Bid Guarantee	N/A	N/A	**<u>**CALCULATIONS FOR *CHARGE TYPE* 1313 ENDED ON APRIL, 2018.**</u> Calculated as per demand response pilot contracts. **Notes:** - Bid guarantee as a payment is Due MP; bid guarantee as a clawback is Due IESO. Bid guarantee is calculated per unit commitment period/event.	Monthly	Either Way	13	N/A	N/A	N/A			Demand Response Pilot
1314	Capacity Obligation – Availability Payment	$CAAP^{m}_{k}$	9.4.7J.1	$\sum H\,CCO^{m}_{k,h} \times CACP^{z}_{h}$	Monthly	Due MP	13	13	N/A	N/A			

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				Where: 'H' is the set of all *settlement hours* within the *availability window* of all *business days* in the relevant *energy market billing period*.									
1315	Capacity Obligation – Availability Charge	$CAAC^{m}_{k}$	4.7J.2.1	In regards to a *capacity market participant* participating with an *hourly demand response resource* or a *capacity dispatchable load resource*: $\sum_{H}(-1) \times Max(0, (CCO^{m}_{k,h} - DREBQ^{m}_{k,h})) \times CACP^{z}_{h} \times CNPF_{tm}$ Where: (a) 'H' is the set of all *settlement hours* within the *availability window* during the relevant *trading day*; (b) If the *capacity market participant* did not submit a *demand response energy bid* for its *hourly demand response resource* or	Daily	Due IESO	13	13	N/A	N/A			

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				capacity dispatchable load resource, as the case may be, for *settlement hour* 'h' in the day-ahead commitment process or failed to maintain such *energy bid* through the *real-time energy market*, $DREBQ^{m}_{k,h} = 0$; (c) In regards to *hourly demand response resource*, if the *demand response energy bids* submitted for *settlement hour* 'h' does not form part of *energy bids* spanning at least four consecutive *settlement hours*, $DREBQ^{m}_{k,h} = 0$; (d) If the *demand response energy bid* submitted in the day-ahead commitment process for *settlement hour* 'h' is not equal to the *demand*									

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				response energy bid submitted in the *real-time market* for the same *settlement hour*, $DREBQ^{m}_{k,h}$ shall be equal to the lesser of the two *demand response energy bids*; and Notwithstanding any of the foregoing, $DREBQ^{m}_{k,h}$ shall not exceed the $CARC^{m}_{k}$ for the *hourly demand response resource* or *capacity dispatchable load resource*, as the case may be. In regards to a *capacity market participant* participating with a *capacity generation resource*, *system-backed capacity import resource, generator-backed capacity import resource* or *capacity storage resource*: $\sum_{H}(-1) \times Max(0, (CCO^{m}_{k,h} - CAEO^{m}_{k,h})) \times CACP^{z}_{h} \times CNPF_{tm}$ Where:									

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				(a) 'H' is the set of all *settlement hours* within the *availability window* during the relevant *trading day*; (b) If the *capacity market participant* did not submit an *energy offer* in the day-ahead commitment process or maintain such *energy offer* in accordance with the applicable *market manual* for *settlement hour* 'h', $CAEO^{m}_{h,k} = 0$; (c) If the *energy offer* submitted in the day-ahead commitment process for *settlement hour* 'h' is not equal to the *energy offer* submitted in the *pre-dispatch* hour for the same *settlement hour*, $CAEO^{m}_{h,k}$ shall be equal to the lesser of the two *energy offers*; (d) If a *capacity storage resource* receives a non-zero *energy dispatch instruction* within the relevant									

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				availability window, the $CAEO^{m}_{h,k}$ for the remaining *settlement hours* of the *availability window* after receiving such non-zero *energy dispatch instruction* shall be equal to the *energy offer* applicable to the *settlement hour* in which they receive such non-zero *energy dispatch instruction.*									
1316	Capacity Obligation – Administration Charge	$CAADM^{m}_{k}$	4.7J.2.3	$(-1) \times CAAP^{m}_{k}$ Where: '$CAAP^{m}_{k}$' is the *capacity auction* availability payment *settlement amount*, calculated in accordance with section 4.7J.1, for *capacity market participant* 'k' at *delivery point* or *intertie metering point* 'm' for the relevant *energy market billing period*.	Monthly	Due IESO	13	13	N/A	N/A			
1317	Capacity Obligation – Dispatch Charge	$CADC^{m}_{k,}$	4.7J.2.2	$(-1) \times DRSQty^{m}_{k,h} \times CACP^{z}_{h} \times CNPF_{tm}$ Where:	Hourly	Due IESO	13	13	N/A	N/A			

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				(a) 'h' is a *settlement hour* in which the *hourly demand response resource* failed to comply with its activation notice, as determined in accordance with the applicable *market manual*. (b) 'tm' is the *energy market billing period* that corresponds to *settlement hour* 'h'.									
1318	Capacity Obligation – Capacity Charge	$CACC^{m}_{k}$	9.7J.2.4	$(-1) \times CAAP^{m}_{k}$ Where: '$CAAP^{m}_{k}$' is the *capacity auction* availability payment *settlement amount*, calculated in accordance with section 4.7J.1, for *capacity market participant* 'k' at *delivery point* or *intertie metering point* 'm' for the relevant *energy market billing period*.	Monthly	Due IESO	13	13	N/A	N/A			
1319	Capacity Obligation – Buy-Out Charge	$CABOC^{m}_{k}$	9.4.7J.3	$=50\% \times \sum H\, CBOC^{m}_{k} \times CACP^{m}_{k} \times (1 - CNPF_{tm})$ Where:	Monthly	Due IESO	13	13	N/A	N/A			

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				(a) 'H' is the set of all *settlement hours* within the *availability window* of all *trading days* from the buy-out effective date to the end of the *commitment period*. (b) 'tm' is the *energy market billing period* that corresponds to the relevant *settlement hour*.									
1320	Capacity Obligation – Dispatch Test Payment and Emergency Activation Payment	$CATAP^{m}_{k,h}$ and $CAEOP^{m}_{k,h}$	9.4.7J.5	**For *capacity auction dispatch test* activations:** $HDRTAPR \times HDRDC^{m}_{k,h}$ **For *emergency operating state* activations:** $Max(0, HDRBP^{m}_{k,h} - Max(0,HOEP_{h})) \times HDRDC^{m}_{k,h}$	Hourly	Due MP	13	13	N/A	N/A			
1321	Capacity Obligation – Capacity Import Call Failure Charge	$CACIF^{m}_{k}$	9.4.7J.2.7	$(-1) \times CAAP^{m}_{k}$ Where: '$CAAP^{m}_{k}$' is the *capacity auction* availability payment *settlement amount*, calculated in accordance	Monthly	Due IESO	N/A	13	N/A	N/A			

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				with section 4.7J.1, for *capacity market participant* 'k' at *delivery point* or *intertie metering point* 'm' for the relevant *energy market billing period*.									
1322	Capacity Obligation – Capacity Deficiency Charge	$CACD^{i}_{k}$	9.4.7J.2.8	$\sum^{H} (-1.5) \times OCMW^{i}_{k} \times CACP^{z}_{h}$ Where: 'H' is the set of all *settlement hours* within the *availability window* of all *trading days* within the relevant *energy market billing period*.	Monthly	Due IESO	N/A	13	N/A	N/A			
1323	Capacity Obligation – In-Period Cleared UCAP Adjustment Charge	$CAIPA^{m}_{k}$	9.4.7J.2.9	(-1 x Max (0, ($CAAP^{m}_{k}$ x (UCAP Adjustment) + $\sum^{H} CAAC^{m}_{k,h}$)) Where: a. $CAAP^{m}_{k}$ is the *capacity obligation* availability payment settlement amount for *capacity market participant* 'k' at delivery point 'm' for the relevant *energy market billing period*,	Monthly	Due IESO							

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				as calculated pursuant to section 4.7J.1. b. $CAAC^{m}_{k,h}$ is the *capacity obligation* availability charge *settlement amount* for *capacity market participant* 'k' at *delivery point* 'm' for *settlement hour* 'h', as calculated pursuant to section 4.7J.2.1. c. 'H' is the set of all *settlement hours* 'h' within the *availability window* of the relevant *energy market billing period*. d. 'UCAP Adjustment' is a de-rate (in %) based on the *hourly demand response resource's* delivered performance during a *capacity auction capacity test*, as determined in accordance with the applicable *market manual*. If the *capacity market participant* has filed a *notice of disagreement* in regards to the outcomes of the *capacity*									

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				auction capacity test in accordance with section 6.8 of Chapter 9 of the *market rules*, and but for filing such *notice of disagreement* the *capacity market participant* would have forfeited any of its *capacity obligation* pursuant to section 19.4.18 of Chapter 7 of the *market rules*, then the UCAP Adjustment shall equal 100%.									
1324	Capacity Obligation – Availability Charge True-up Payment	$CAACT^{m}_{k}$	9.4.7J.6	(Min ((-1) x $\sum$ TM (($\sum$ D $CAAC^{m}_{k}$) + UCAP Adjustment x $CAAP^{m}_{k}$ + $CAIPA^{m}_{k}$), $\sum$ H Max (0,(RAC_{k} – $CCO_{k,h}$) x $CACP_{h}$ x $CNPF_{tm}$)) Where: (a) $CAAC^{m}_{k}$ is the *capacity obligation* availability charge *settlement amount* for *capacity market participant* 'k' at *delivery*		Due *IESO*							

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				point 'm' for the relevant *trading day*, as calculated as the sum of the *capacity obligation* availability charge *settlement amount* of each *settlement hour* within the relevant *availability window* determined pursuant to section 4.7J.2.1; (b) 'UCAP Adjustment' is a de-rate (in %) based on the *hourly demand response resource's* delivered performance during a *capacity auction capacity test* performed during the relevant *obligation period*, as determined in accordance with the applicable *market manual*; (c) $CAAP^{m}_{k}$ is the *capacity obligation* availability payment *settlement amount* for *capacity market participant* 'k' at									

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				delivery point 'm' for the relevant *energy market billing period*, as calculated pursuant to section 4.7J.1 of Chapter 9 of the *market rules*; (d) $CAIPA^{m}_{k}$ is the *capacity obligation* in-period *cleared UCAP* adjustment charge *settlement amount* for *capacity market participant* 'k' at delivery point 'm' for the relevant *energy market billing period*, as calculated pursuant to section 4.7J.2.9 of Chapter 9 of the *market rules*; (e) 'D' is the set of all *trading days* within the relevant *energy market billing period*; (f) 'tm' is the *energy market billing periods* associated with *settlement hour* 'h'									

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				within the relevant *obligation period*; (g) 'TM' is the set of all *energy market billing periods* within the relevant *obligation period*; and (h) 'H' is the set of all *settlement hours* 'h' within the *availability window* of the relevant *obligation period*.									
1325	Capacity Obligation – Capacity Auction Charges True-up Payment	$CACT^{m}{}_{k}$	9.4.7J.7	-1xMin (0, ($\sum_{H} TD_{C,k,h^{m}}$ + $\sum_{H} TD_{P,k,h^{m}}$)) (a) $TD_{C,k,h^{m}}$ is the total dollar value of all *settlement amounts* 'C' for *capacity market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' in the relevant *obligation period*, where: a. 'C' is the set of the *settlement amounts*									

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				applied in accordance with MR Ch. 9 ss. 4.7J.2.1, 4.7J.2.1A, 4.7J.2.3, 4.7J.2.4, 4.7J.2.5, 4.7J.2.6, 4.7J.2.7, 4.7J.2.8, and 4.7J.2.9. (b) TD_{P,k,h^m} is the total dollar value of all *settlement amounts* 'P' for *capacity market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' in the relevant *obligation period*, where: a. 'P' is the set of the *settlement amounts* applied in accordance with MR Ch. 9 ss. 4.7J.1 and 4.7J.6 (c) 'H' is the set of all *settlement hours* 'h' within the *availability window* of									

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				the relevant *obligation period*.									
1330	On behalf of the former OPA for the DR2 Program - Availability Payment Settlement Amount	N/A	N/A	**<u>**CALCULATIONS FOR *CHARGE TYPE* 1330 ENDED ON FEBRUARY 28, 2015.**</u> $= \sum_H \text{CoMW}_h \times \text{AR} \times \text{ILSR}$ Where: 'CoMW' (Contracted MW), means the MW specified in the DR2 Schedule(s) for a given Settlement Account which the Participant agrees to Load Shift in each On-Peak Contract hour. 'AR' (Availability Rate), means the availability rate, expressed in $/MW, in the amount as specified by the OPA from time to time on the OPA Website pursuant to the DR2 Program Rules. 'H' is the total On-Peak contract hours in a Contract Month. 'ILSR' (Implied Load Shift Ratio), has the meaning as defined in	Monthly	Due DR2-participants Either way	13	N/A	N/A	N/A			*Former OPA* DR2 Contract. The DR2 program was last settled on the February 2015 settlement statements and invoice.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				OPA's DR2 Program Rules and is calculated as follows: ILSR = (−1) × [Implied Load Shift − ((3/4)(Load Shift Credit))] / Implied Load Shift Requirement									
1331	On behalf of the former OPA for the DR2 Program - Availability Set-Off Settlement Amount	N/A	N/A	**<u>**CALCULATIONS FOR *CHARGE TYPE* 1331 ENDED ON FEBRUARY 28, 2015.**</u> The charge to a DR participant is the highest of amounts A, B or C plus amount D; where A, B and C cannot occur within an on-peak period that was subject to D. **A: Availability Set-Off (Reliability)** $= \sum_H \text{PSO}_h \times \text{AR} \times \text{CoMW}_h \times \text{ILSR}$ This formula applies when the Actual MW Reliability Ratio for a given Settlement Account is less than 95% during the Summer and Winter seasons and less than 90% during the shoulder seasons.	Monthly	Due DR2-participants Either way	13	N/A	N/A	N/A			*Former OPA* Program Rules. The DR2 program was last settled on the February 2015 settlement statements and invoice.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				The Actual MW Reliability Ratio, which shall not be greater than 100%, shall be calculated as follows: - For each On-Peak Contract Hour, the Actual MW Reliability Ratio is defined as the result of the baseline MW minus the actual MW divided by the confirmed MW. 'PSO' (Performance Set-Off Factor) refers to a set of factors defined in the OPA DR2 Program Rules. 'AR' has the same meaning as in CT1330. 'CoMW' has the same meaning as in CT1330. 'H' is the set of all hours 'h' in the On-Peak Contract period where the required reliability is not met. 'ILSR' has the same meaning as in CT1330. **B: Availability Set-Off (Timely Confirmation)**									

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				$= PSO \times AR \times CoMW_h \times H \times ILSR$ This formula applies when the Participant has failed to deliver, or delivers late, a Confirmation that is required by the IESO pursuant to the DR2 Program Rules. Where: 'PSO' has the same meaning as defined above. 'AR' has the same meaning as in CT1330. 'CoMW' has the same meaning as in CT1330. 'H' is the set of all hours in the On-Peak Contract period. 'ILSR' has the same meaning as in CT1330. **C: Availability Set-Off (Low Confirmation)** $= \sum_H PSO \times AR \times (CoMW_h - CMW) \times ILSR$									

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				This formula applies when the Confirmed MW is less than the product of the Required Reliability Ratio and the Contracted MW for one or more On-Peak Contract hours. Where: 'PSO' has the same meaning as defined above. 'AR' has the same meaning as in CT1330. 'CoMW' has the same meaning as in CT1330. 'CMW' (Confirmed MW) means the number of MW available to shift by the Participant. 'H' is the set of all confirmed hours 'h' when the Confirmed MW's are: - Less than 95% during the Summer and Winter seasons or - Less than 90% during the shoulder seasons of the Contracted MW. 'ILSR' has the same meaning as in CT1330.									

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				D: Availability Set-Off (Non-Performance) $= PSO \times AR \times CoMW_h \times H \times ILSR$ This formula applies when the Participant has taken an Extended Planned Non-Performance Event or Single Day Planned Non-Performance Event. Where: 'PSO' has the same meaning as defined above. 'AR' has the same meaning as in CT1330. 'CoMW' has the same meaning as in CT1330. 'H' is the set of all hours in the On-Peak Contract period. 'ILSR' has the same meaning as in CT1330.									
1332	On behalf of the former OPA for the DR2 Program - Utilization Payment Settlement Amount	N/A	N/A	**<u>**CALCULATIONS FOR *CHARGE TYPE* 1332 ENDED ON FEBRUARY 28, 2015.**</u> The monthly Utilization Payment to a DR2 participant is the sum of the	Monthly	Due DR2-participants Either way	13	N/A	N/A	N/A			*Former OPA* DR2 Contract. The DR2 program was last settled on the February 2015 settlement

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				weekly utilization payments for the contract month and calculated as follows: Weekly Utilization payment $= \sum_P \text{Max}\left[\begin{pmatrix}\text{GHDiff} - \\ \text{AHDiff}\end{pmatrix}, 0\right]$ $\text{x Min}\left[\begin{matrix}(\text{CoMWh} \times 1.15), \\ (\text{Curt}_p)\end{matrix}\right] \times$ ILSR Where: 'GHDiff' (Guaranteed weekly HOEP Differential), means the weekly differential rate, expressed in $/MWh, as specified by the *OPA* 'AHDiff' (Actual weekly HOEP Differential), is equal to the average actual HOEP for all hours of the useable On-Peak Contract Periods in the Week less the average actual HOEP for all hours in the Off-Peak Period for the same Week. 'CoMWh' (Contracted MWh), means the MWh specified in the DR2 Schedule(s) for a given Settlement Account which the Participant agrees									statements and invoice.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				to Load Shift in each On-Peak Contract Period. 'Curt' (Curtailment), means the number of MWh Curtailed by a Participant for each useable on-peak contract period, and shifted to the off-peak period as measured through the use of electricity meter(s). 'P' is the total number of On-Peak Contract Periods 'p' for a Participant in a Contract Week 'ILSR' has the same meaning as in CT1330.									
1333	On behalf of the former OPA for the DR2 Program - Utilization Set-Off Settlement Amount	N/A	N/A	**<u>**CALCULATIONS FOR *CHARGE TYPE* 1333 ENDED ON FEBRUARY 28, 2015.**</u> The charge to a DR participant is highest of **A**, **B** or **C** where A, B and C cannot occur within an on-peak period that was subject to an Availability Set-Off (Non-Performance) event: **A: Utilization Set-Off (Reliability)**	Monthly	Due DR2-participants Either way	13	N/A	N/A	N/A			*Former OPA* DR2 Contract. The DR2 program was last settled on the February 2015 settlement statements and invoice.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				$= \sum_P \text{PSO}$ $\times$ Max[(GHDiff – AHDiff),0] $\times$ $\text{CoMWh}_p \times$ ILSR This formula applies when the Actual MWh Reliability Ratio for a given Settlement Account is less than 95% during the Summer and Winter seasons and less than 90% during the shoulder seasons. The Actual MWh Reliability Ratio, which shall not be greater than 100%, shall be calculated as follows: - For each On-Peak Contract Period, the Actual MWh Reliability Ratio is defined as the result of the baseline MWh minus the actual MWh divided by the product of the confirmed MW and the On-Peak Contract Hours. Where: 'PSO' (Performance Set-Off Factor) refers to a set of factors defined in the *OPA's* Program Rules.									

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				'GHDiff' has the same meaning as in CT1332. 'AHDiff' has the same meaning as in CT1332. 'CoMWh' has the same meaning as in CT1332. 'P' is the total number of On-Peak Contract Periods 'p' for a Participant in a Contract Month. 'ILSR' has the same meaning as in CT1330. **B: Utilization Set-Off (Timely Confirmation)** $= \sum_P \text{PSO} \times \text{Max}[(\text{GHDiff} - \text{AHDiff}),0] \times \text{CoMWh}_p \times \text{ILSR}$ This formula applies when the Participant has failed to deliver, or delivers late, a Confirmation that is required by the IESO pursuant to the DR2 Program Rules. Where:									

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				'PSO' has the same meaning as defined above. 'GHDiff' has the same meaning as in CT1332. 'AHDiff' has the same meaning as in CT1332. 'CoMWh' has the same meaning as in CT1332. 'P' is the total such On-Peak Contract Periods 'p' for a Participant in a Contract Month when the Participant has failed to deliver, or delivers late, a Confirmation. 'ILSR' has the same meaning as in CT1330. **C: Utilization Set-Off (Low Confirmation)** $= \sum_P \text{PSO} \times \text{Max}$ $[(\text{GHDiff} - \text{AHDiff}),0]$ $\times \left(\text{CoMWh} - \text{CMWh}_p\right)$ $\times \text{ ILSR}$ This formula applies when the Confirmed MWh are less than the product of the Required Reliability									

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				Ratio and the Contracted MWh for an On-Peak Contract Period. Where: 'PSO' has the same meaning as defined above. 'GHDiff' has the same meaning as in CT1332. 'AHDiff' has the same meaning as in CT1332. 'CoMWh' has the same meaning as in CT1332. 'CMWh' (Confirmed MWh) means the MWh available confirmed for shifting by the Participant. 'P' is the total such On-Peak Contract Periods 'p' for a Participant in a Contract Month. 'ILSR' has the same meaning as in CT1330.									
1334	On behalf of the former OPA for the DR2 Program – Meter Data Set-Off Settlement Amount	N/A	N/A	**<u>**CALCULATIONS FOR *CHARGE TYPE* 1334 ENDED ON FEBRUARY 28, 2015.**</u> $= MDSF \times (TD_{k,1330} / NoW_k)$	Monthly	Due DR2-participants Either way	13	N/A	N/A	N/A			*Former OPA* DR2 Contract. The DR2 program was last settled on the February 2015 settlement

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				This formula applies when the complete set of weekly meter data for a Settlement Account is not received by 15:00 EST on the first Business Day of the following week. The formula recovers a percentage of the Availability Payment, as pro-rated for that week in question. Where: 'MDSF' (Meter Data Set-Off Factor), is an increasing factor for every week that the full data remains undelivered. The factor is equal to: - 20% for the first week that the full data remains undelivered; - 33% for the second week that the full data remains undelivered; - 50% for the third week that the full data remains undelivered; and - 100% for the fourth week that the full data remains undelivered. $TD_{k,1330}$ is the *settlement amount* of *charge type* 1330 for month 'k' for the DR2 participant.									statements and invoice.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				'NoW' (Number of Weeks) means the number of Weeks contained in the Contract month. 'k' is the Contract month.									
1335	On behalf of the former OPA for the DR2 Program - Buy-Down Settlement Amount	N/A	N/A	**<u>**CALCULATIONS FOR *CHARGE TYPE* 1335 ENDED ON FEBRUARY 28, 2015.**</u> Buy-Down means the act by the Participant of reducing its Contracted MW and/or the number of On-Peak Contract hours from participation in DR2. For the Buy-Down of Seasonal Contracted MW the payment is: = (SCMWR × BDR × CHE) Where: 'SCMWR' (Seasonal Contracted MW Reduction), means the MW of demand reduction in the Seasonal Contracted MWs. 'BDR' (Buy-Down Rate), means the Buy-Down Rate, expressed in $/MW.	Monthly	Due DR2-participants Either way	13	N/A	N/A	N/A			*Former OPA* DR2 Contract. The DR2 program was last settled on the February 2015 settlement statements and invoice.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				'CHE' (on-peak Contract Hours Elapsed), means the number of On-Peak Contract Hours that have elapsed in the Schedule Term up to the date that the reduction takes effect. For the Buy-Down of the number of On-Peak Contract hours, the payment is: = (CoMW × PRCH × BDR × CHE) Where: 'CoMW' has the same meaning as in CT1330. 'PRCH' (Percent Reduction in Contract Hours), means the percent reduction in On-Peak Contract Hours requested. 'BDR' has the same meaning as defined above. 'CHE' has the same meaning as defined above.									
1336	On behalf of the former OPA for the DR2 Program -	N/A	N/A	**<u>**CALCULATIONS FOR *CHARGE TYPE* 1336 ENDED ON FEBRUARY 28, 2015.**</u>	Monthly	Due DR2-participants Either way	13	N/A	N/A	N/A			*Former OPA* DR2 Contract. The DR2 program was last

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
	Miscellaneous Settlement Amount			Reserved for DR2 payments or charges of a miscellaneous nature not specifically covered under Charge Types 1330 through 1335.									settled on the February 2015 settlement statements and invoice.
1340	On behalf of the former OPA for the DR3 Program – Availability Payment Settlement Amount	N/A	N/A	**<u>**CALCULATIONS FOR *CHARGE TYPE* 1340 ENDED ON APRIL 30, 2015.**</u> $= HA_H \times MCMW_h \times AAR$ Where: 'HA' (Hours of Availability), means those hours within which a Participant shall maintain a Contracted Dispatch Period to be available for potential Curtailment of that Participant's Monthly Contracted MW. 'MCMW' (Monthly Contracted MW), means the MW of demand reduction capacity for a specific Contract Month as identified in one or more DR3 Contact Schedule(s). 'AAR' (Adjusted Availability Rate), means an amount equal to the Availability Rate, expressed in $/MWh, as increased by the	Monthly	Due DR3-participants Either way	13	N/A	N/A	N/A			*Former OPA* DR3 Contract. The DR3 program was last settled on the April 2015 settlement statements and invoice.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				Availability Premium or as decreased by the Availability Discount, as the case may be. 'H' is the total hours a Participant is available in a Contract Month.									
1341	On behalf of the former OPA for the DR3 Program – Availability Over-Delivery Settlement Amt	N/A	N/A	**<u>**CALCULATIONS FOR *CHARGE TYPE* 1341 ENDED ON APRIL 30, 2015.**</u> $= \sum_H (\mathrm{CMW}_h - \mathrm{MCMW}_h) \times \mathrm{AODR}_h$ Applicable only in response to an open standby notification. Where: 'CMW' (Confirmed MW), means the number of MW available for Curtailment by the Participant. 'CMW' is limited to the lesser of the Monthly Contracted MW plus 15 MW and 130% of the Monthly Contracted MW. 'MCMW' has the same meaning as in CT1340.	Monthly	Due DR3-participants Either way	13	N/A	N/A	N/A			Former *OPA* DR3 Contract. The DR3 program was last settled on the April 2015 settlement statements and invoice.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				'AODR' (Availability Over-Delivery Rate), means the over-delivery rate as specified by the *OPA*. 'H' is the set of all hours 'h' in the Contract month where the 'CMW' exceeded the 'MCMW'.									
1342	On behalf of the former OPA for the DR3 Program – Availability Set-Off Settlement Amount	N/A	N/A	**<u>**CALCULATIONS FOR *CHARGE TYPE* 1342 ENDED ON APRIL 30, 2015.**</u> The charge to a DR participant is highest of **A**, **B** or **C:** **A: Availability Set-Off (Reliability)** $= \sum_H \mathrm{PSO}_h \times \mathrm{AAR} \times \mathrm{MCMW}_h$ This formula applies when the Reliability Rate for a given Settlement Point is less than 85% during any meter interval of an Activation Hour, or where the Participant is not Fully Available for Curtailment as defined in the *OPA* DR3 Program Rules. Where:	Monthly	Due DR3-participants Either way	13	N/A	N/A	N/A			Former *OPA* DR3 Contract. The DR3 program was last settled on the April 2015 settlement statements and invoice.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				For each metered interval, the Reliability Rate at a settlement point is defined as the actual reduction divided by the requested reduction; however, the Reliability Rate cannot exceed 100%. 'PSO' (Performance Set-Off Factor) refers to a set of factors defined in the *OPA* DR3 Program Rules. 'AAR' has the same meaning as in CT1340. 'MCMW' has the same meaning as in CT1340. 'H' is the set of all activation hours 'h' for the activation period. **B: Availability Set-Off (Timely Confirmation)** $= PSO \times AAR \times MCMW_h \times CDP$ This formula applies when the Participant, regardless of Activation, has failed to deliver, or delivers late, a Confirmation that is required by the *IESO* pursuant to the DR3 Program Rules.									

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				Where: 'CDP' (Contracted Dispatch Period) means four consecutive hours. Each Contracted Dispatch Period shall occur within the hours of Availability, and shall occur within and no more than once in accordance with the Daily Schedule. 'PSO' has the same meaning as defined above. 'AAR' has the same meaning as in CT1340. 'MCMW' has the same meaning as in CT1340. **C: Availability Set-Off (Low Confirmation)** $= \sum_H (\text{PSO} \times \text{AAR} \times (\text{MCMW}_h - \text{CMW})$ This formula applies when the Confirmed MW's are less than 95% of the Monthly Contracted MW for a Confirmed Hour of the Contracted Dispatch Period.									

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				Where: 'PSO' has the same meaning as defined above. 'AAR' has the same meaning as in CT1340. 'MCMW' has the same meaning as in CT1340. 'CMW' has the same meaning as in CT1341. 'H' is the set of all confirmed hours 'h' when the Confirmed MW's are less than 95% of the Monthly Contracted MW for the Contracted Dispatch Period.									
1343	On behalf of the former OPA for the DR3 Program – Utilization Payment Settlement Amount	N/A	N/A	**<u>**CALCULATIONS FOR *CHARGE TYPE* 1343 ENDED ON APRIL 30, 2015.**</u> $= [\sum_H (\text{Curt}_h \times \text{UR}_h)] - [\sum_H (\text{NG}_h \times \text{MIN}(\text{HOEP}, \text{UR}_h))]$ Where: 'Curt' (Curtailment), means the number of MWh Curtailed by a Participant when requested by the	Monthly	Due DR3-participants Either way	13	N/A	N/A	N/A			Former *OPA* DR3 Contract. The DR3 program was last settled on the April 2015 settlement statements and invoice.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				IESO, as measured through the use of electricity meter(s). Curtailment shall not exceed the product of the Activation MW and the activation period requested by the *IESO*, plus the lesser of an additional 15% of the Activation MW per hour of the activation period, OR 15 MWh per hour of the activation period. 'UR' (Utilization Rate), means the rates, expressed in $/MWh, as specified by the *OPA*. 'NG' (Net Generation), means the MWh of net electricity generated by any contributor that is a behind the meter generator. 'H' is the total hours 'h' a Participant is activated in a Contract Month.									
1344	On behalf of the former OPA for the DR3 Program – Utilization Set-Off Settlement Amount	N/A	N/A	**<u>**CALCULATIONS FOR *CHARGE TYPE* 1344 ENDED ON APRIL 30, 2015.**</u> The charge to a DR participant is highest of **A**, **B** or **C:** **A: Utilization Set-Off (Reliability)**	Monthly	Due DR3-participants Either way	13	N/A	N/A	N/A			Former *OPA* DR3 Contract. The DR3 program was last settled on the April 2015 settlement statements and invoice.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				$= \sum_H \text{PSO}_h \times \text{UR} \times \text{MCMW}_h$ This formula applies when the Reliability Rate for a given Settlement Point is less than 85% during any meter interval of an Activation Hour. Where: For each metered interval, the Reliability Rate at a settlement point is defined as the actual reduction divided by the requested reduction; however, the Reliability Rate cannot exceed 100%. 'PSO' (Performance Set-Off Factor) refers to a set of factors defined in the *OPA's* Program Rules. 'UR' has the same meaning as in CT1343. 'MCMW' has the same meaning as in CT1340. 'H' is the set of all activation hours 'h' for the activation period. **B: Utilization Set-Off (Timely Confirmation)**									

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				= PSO × UR × $MCMW_h$ × CDP This formula applies when the Participant, regardless of Activation, has failed to deliver, or delivers late, a Confirmation that is required by the *IESO* pursuant to the DR3 Program Rules. Where: 'CDP' (Contracted Dispatch Period) means four consecutive hours. Each Contracted Dispatch Period shall occur within the hours of Availability, and shall occur within and no more than once in accordance with the Daily Schedule. 'PSO' has the same meaning as defined above. 'UR' has the same meaning as in CT1343. 'MCMW' has the same meaning as in CT1340 **C: Utilization Set-Off (Low Confirmation)**									

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				$= \sum_H (\text{PSO} \times \text{UR} \times (\text{MCMW}_h - \text{CMW})$ This formula applies when the Confirmed MW's are less than 95% of the Monthly Contracted MW for a Confirmed Hour of the Contracted Dispatch Period. Where: 'PSO' has the same meaning as defined above. 'UR' has the same meaning as in CT1343. 'MCMW' has the same meaning as in CT1340. 'CMW' has the same meaning as in CT1341. 'H' is the set of all confirmed hours 'h' when the Confirmed MW's are less than 95% of the Monthly Contracted MW for the Contracted Dispatch Period.									
1345	On behalf of the former OPA for the DR3 Program – Planned Non-	N/A	N/A	**<u>**CALCULATIONS FOR *CHARGE TYPE* 1345 ENDED ON APRIL 30, 2015.**</u>	Monthly	Due DR3-participants Either way	13	N/A	N/A	N/A			Former *OPA* DR3 Contract. The DR3 program was last settled on the

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
	Performance Event Set-Off Amt			The Planned Non-Performance Availability Set-Off applies for any day for which a participant has requested a Non-Performance Event as part of either a Single Day Non-Performance Event or a part of an Extended Period Planned Non-Performance Event. The monthly set-off calculation is the sum of all: 1. Non-Activation Day Non-Performance Availability Set-Off s and 2. Activation Day Non-Performance Availability Set-Offs. For 1.) The Non-Activation Day Non-Performance Availability Set-Off amount is: $= (AAR \times MCMW_h \times HANE_H)$ Where: 'AAR' has the same meaning as in CT1340.									April 2015 settlement statements and invoice.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				'MCMW' has the same meaning as in CT1340. 'HANE' (Hours of Availability for a Non-Performance Event), represents the Hours of Availability for all days in the contract month for which a planned Non-Performance Event is requested and for which an Activation Notice is not received by the participant. For 2.) The Activation Day Non-Performance Availability Set-Off amount is: $= (OH \times AAR \times MCMW_h \times NEWF_H)$ Where: 'OH' (Opportunity Hours), means 64 if Option A is applicable to the Settlement Account; or 32 if Option B is applicable to the Settlement Account. 'AAR' has the same meaning as in CT1340. 'MCMW' has the same meaning as in CT1340.									

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				'NEWF' (Non-Performance Event Weighting Factor), means 50%, if the Actual Activated MWh per interval, as averaged over all of the Intervals in the Contracted Dispatch Period for the Activation, is greater than or equal to the product of the Monthly Contracted MW and 1/12 of an hour; or 100% otherwise.									
1346	On behalf of the former OPA for the DR3 Program – Meter Data Set-Off Settlement Amount	N/A	N/A	**<u>**CALCULATIONS FOR *CHARGE TYPE* 1346 ENDED ON APRIL 30, 2015.**</u> = MDSF × (HA_H × $MCMW_h$ × AAR) This formula applies when the complete set of weekly meter data and proof of any Forced Outage(s) for a Settlement Account is not received by 15:00 EST on the first Business Day of the following week. The formula recovers a percentage of the availability payment for the applicable week. Where: 'MDSF' (Meter Data Set-Off Factor), is an increasing factor for every week	Monthly	Due DR3-participants Either way	13	N/A	N/A	N/A			Former *OPA* DR3 Contract. The DR3 program was last settled on the April 2015 settlement statements and invoice.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				that the full data remains undelivered. The factor is equal to: - 20% for the first week that the full data remains undelivered; - 33% for the second week that the full data remains undelivered; - 50% for the third week that the full data remains undelivered; and - 100% for the fourth week that the full data remains undelivered. 'HA' has the same meaning as in CT1340. 'MCMW' has the same meaning as in CT1340. 'AAR' has the same meaning as in CT1340. 'H' is the total hours a Participant is available for the applicable week.									
1347	On behalf of the former OPA for the DR3 Program – Buy-Down Settlement Amount	N/A	N/A	**<u>**CALCULATIONS FOR *CHARGE TYPE* 1347 ENDED ON APRIL 30, 2015.**</u> Buy-Down means the act by the Participant of reducing its Monthly	Monthly	Due DR3-participants Either way	13	N/A	N/A	N/A			Former *OPA* DR3 Contract. The DR3 program was last settled on the April 2015 settlement

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				Contracted MW and/or removing Daily Schedules from participation in DR3. For the Buy-Down of Monthly Contracted MW the payment is: = (MCMWR × BDR × HAE) Where: 'MCMWR' (Monthly Contracted MW Reduction), means the MW of demand reduction in the Monthly Contracted MWs. 'BDR' (Buy-Down Rate), means the Buy-Down Rate, expressed in $/MW. 'HAE' (Hours of Availability Elapsed), means the number of Hours of Availability that have elapsed in the Schedule Term up to the date that the reduction takes effect. For the Buy-Down of the Daily Schedules the payment is: = (MCMW × RD × BDR × HAE) Where:									statements and invoice.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				'MCMW' has the same meaning as in CT1340. 'RD' (Requested Days), means the number of Business Days per week from which the Hours of Availability are to be removed. 'BDR' has the same meaning as defined above. 'HAE' has the same meaning as defined above.									
1348	On behalf of the former OPA for the DR3 Program – Miscellaneous Settlement Amount	N/A	N/A	**<u>**CALCULATIONS FOR *CHARGE TYPE* 1348 ENDED ON APRIL 30, 2015.**</u> Reserved for DR3 payments or charges of a miscellaneous nature not specifically covered under Charge Types 1340 through 1347.	Monthly	Due DR3-participants Either way	13	N/A	N/A	N/A			Former *OPA* DR3 Contract. The DR3 program was last settled on the April 2015 settlement statements and invoice.
1350	Capacity Based Recovery Amount for Class A Loads	CAU^{m}_{k}	9.4.7J.8	$\Sigma_{H,M,}TD_{C,k,h^{m}} * PDF_{k}$ Where: (a) 'H' is the set of all *settlement hours 'h'* in the relevant *energy market billing period*	Monthly	Due IESO	13	N/A	N/A	N/A			See comments under charge type 147

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				(b) 'M' is the set of all *delivery points 'm'* of *market participant* 'k' (c) '$TD_{C,k,h}^{m}$' is total dollar value of all *settlement amounts* 'C' for *capacity market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' in the relevant *energy market billing period*, where: i. 'C' is the set of the *settlement amounts* applied in accordance with MR Ch. 9 ss. 4.7J.1, 4.7J.2, 4.7J.3, 4.7J.5, 4.7J.6, and 4.7J.7 (d) 'PDF_k' is the Peak Demand Factor for 'Class A Market Participant' or Distributor 'k' for the relevant *energy market billing period*, as determined in accordance with *applicable law,* where if the 'Class A Market Participant' or Distributor 'k' ceases to be a 'Class A									

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				Market Participant' in respect of the relevant *load facility* during the relevant *energy market billing period,* the PDF_k shall be pro-rated accordingly.									
1351	Capacity Based Recovery Amount for Class B Loads	CAU^m_k	N/A	For Fort Frances Power Corporation Distribution Inc.: $(\Sigma_{H,M} TD_{C,k,h^m} - TD_{C1350,k,h^m}) \times MAX((\Sigma_H{}^{M,T} AQEW_{k,h}{}^{m,t} + EGEI_k - EEQ),0)$ / Class B Load Where: a) '$TD_{C,k,h}{}^m$' is total dollar value of all *settlement amounts* 'C' for *capacity market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' in the relevant *energy market billing period*, where 'C' is the set of the *settlement amounts* applied in accordance with MR Ch. 9 ss. 4.7J.1, 4.7J.2, 4.7J.3, 4.7J.5, 4.7J.6, and 4.7J.7. b) '$TD_{C1350,k,h}{}^m$' is total dollar value of *settlement amounts*	Monthly	Due IESO	13	N/A	N/A	N/A			See comments under charge type 148

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				applied pursuant to section 4.7J.8.1 for *capacity market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' in the relevant *energy market billing period*; For other Class B *Market Participant*s and Distributors: $(\Sigma_{H,M}TD_{C,k,h^m} - TD_{C1350,k,h^m}) \times MAX((\Sigma_H{}^{M,T}AQEW_{k,h}{}^{m,t} + EGEI_k - GA_AQEW_{g,k,h,M}{}^{m,t} - PGS_{h,M}),0) / \text{Class B Load}$ Where: a) '$TD_{C,k,h}{}^m$' is total dollar value of all *settlement amounts* 'C' for *capacity market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' in the relevant *energy market billing period*, where 'C' is the set of the *settlement amounts* applied in accordance with MR Ch. 9 ss. 4.7J.1, 4.7J.2, 4.7J.3, 4.7J.5, 4.7J.6, and 4.7J.7.									

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				b) '$TD_{C1350,k,h}^{m}$' is total dollar value of *settlement amounts* applied pursuant to section 4.7J.8.1 for *capacity market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' in the relevant ; c) Class B load is calculated as follows: $(\Sigma_K(\text{MAX}(\Sigma_H{}^{\text{M,T}}\text{AQEW}_{\text{k,h}}{}^{\text{m,t}}+\text{EGEI}_k-\text{EEQ}-\Sigma_H{}^{\text{M,T}}\text{GA_AQEW}_{\text{g,k,h,M}}{}^{\text{m,t}}-\Sigma_H\text{PGS}_{\text{h,M}},0)))-\Sigma_K U_k$ Where: i) 'H' is the set of all *settlement hours* 'h' in the month. ii) 'K' is the set of all *market participants* 'k'. iii) 'M' is the set of all *delivery points* 'm' of *market participant* 'k'. iv) 'C' is the set of the following *charge types* 'c': 1300, 1301, 1302,									

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				1303, 1304, 1305, 1306, 1307 and 1308, 1309, 1310, 1311, 1312 and 1313 and 1314 to 1320, 1321, 1322.									
1380	Demand Response 2 Availability Payment Balancing Amount	N/A	N/A	**<u>CALCULATIONS FOR *CHARGE TYPE* 1380 ENDED ON FEBRUARY 28, 2015.</u>** $\Sigma_K \mathrm{TD}_{k,1330}$ Where 'K' is the set of all DR2 participants 'k'. Where $\mathrm{TD}_{k,1330}$ is the *settlement amount* of *charge type* 1330 for the month for DR2 participant 'k'.	Monthly	Due *OPA*	0	N/A	N/A	N/A			Former *OPA* DR2 Contract. The DR2 program was last settled on the February 2015 settlement statements and invoice.
1381	Demand Response 2 Availability Set-Off Balancing Amount	N/A	N/A	**<u>CALCULATIONS FOR *CHARGE TYPE* 1381 ENDED ON FEBRUARY 28, 2015.</u>** $\Sigma_K \mathrm{TD}_{k,1331}$ Where 'K' is the set of all DR2 participants 'k'. Where $\mathrm{TD}_{k,1331}$ is the *settlement amount* of *charge type* 1331 for the month for DR2 participant 'k'.	Monthly	Due *OPA*	0	N/A	N/A	N/A			Former *OPA* DR2 Contract. The DR2 program was last settled on the February 2015 settlement statements and invoice.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
1382	Demand Response 2 Utilization Payment Balancing Amount	N/A	N/A	**<u>**CALCULATIONS FOR *CHARGE TYPE* 1382 ENDED ON FEBRUARY 28, 2015.**</u> $\Sigma_K \mathrm{TD}_{\mathrm{k},1332}$ Where 'K' is the set of all DR2 participants 'k'. Where $\mathrm{TD}_{\mathrm{k},1332}$ is the *settlement amount* of *charge type* 1332 for the month for DR2 participant 'k'.	Monthly	Due *OPA*	0	N/A	N/A	N/A			Former *OPA* DR2 Contract. The DR2 program was last settled on the February 2015 settlement statements and invoice.
1383	Demand Response 2 Utilization Set-Off Balancing Amount	N/A	N/A	**<u>**CALCULATIONS FOR *CHARGE TYPE* 1383 ENDED ON FEBRUARY 28, 2015.**</u> $\Sigma_K \mathrm{TD}_{\mathrm{k},1333}$ Where 'K' is the set of all DR2 participants 'k'. Where $\mathrm{TD}_{\mathrm{k},1333}$ is the *settlement amount* of *charge type* 1333 for the month for DR2 participant 'k'.	Monthly	Due *OPA*	0	N/A	N/A	N/A			Former *OPA* DR2 Contract. The DR2 program was last settled on the February 2015 settlement statements and invoice.
1384	Demand Response 2 Meter Data Set-Off Balancing Amount	N/A	N/A	**<u>**CALCULATIONS FOR *CHARGE TYPE* 1384 ENDED ON FEBRUARY 28, 2015.**</u> $\Sigma_K \mathrm{TD}_{\mathrm{k},1334}$	Monthly	Due *OPA*	0	N/A	N/A	N/A			Former *OPA* DR2 Contract. The DR2 program was last settled on the February 2015 settlement

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				Where 'K' is the set of all DR2 participants 'k'. Where $TD_{k,1334}$ is the *settlement amount* of *charge type* 1334 for the month for DR2 participant 'k'.									statements and invoice.
1385	Demand Response 2 Buy-Down Balancing Amount	N/A	N/A	**<u>CALCULATIONS FOR *CHARGE TYPE* 1385 ENDED ON FEBRUARY 28, 2015.</u> $\Sigma_K TD_{k,1335}$ Where 'K' is the set of all DR2 participants 'k'. Where $TD_{k,1335}$ is the *settlement amount* of *charge type* 1335 for the month for DR2 participant 'k'.	Monthly	Due *OPA*	0	N/A	N/A	N/A			*Former OPA* DR2 Contract. The DR2 program was last settled on the February 2015 settlement statements and invoice.
1386	Demand Response 2 Miscellaneous Balancing Amount	N/A	N/A	**<u>CALCULATIONS FOR *CHARGE TYPE* 1386 ENDED ON FEBRUARY 28, 2015.</u> $\Sigma_K TD_{k,1336}$ Where 'K' is the set of all DR2 participants 'k'. Where $TD_{k,1336}$ is the *settlement amount* of *charge type* 1336 for the month for DR2 participant 'k'.	Monthly	Due *OPA*	0	N/A	N/A	N/A			*Former OPA* DR2 Contract. The DR2 program was last settled on the February 2015 settlement statements and invoice.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
1390	Demand Response 3 Availability Payment Balancing Amount	N/A	N/A	**<u>CALCULATIONS FOR *CHARGE TYPE* 1390 ENDED ON APRIL 30, 2015.</u>** $\Sigma_K \mathrm{TD}_{k,1340}$ Where 'K' is the set of all DR3 participants 'k'. Where $\mathrm{TD}_{k,1340}$ is the *settlement amount* of *charge type* 1340 for the month for DR3 participant 'k'.	Monthly	Due *OPA*	0	N/A	N/A	N/A			*Former OPA* DR3 Contract. The DR3 program was last settled on the April 2015 settlement statements and invoice.
1391	Demand Response 3 Availability Over-Delivery Balancing Amount	N/A	N/A	**<u>CALCULATIONS FOR *CHARGE TYPE* 1391 ENDED ON APRIL 30, 2015.</u>** $\Sigma_K \mathrm{TD}_{k,1341}$ Where 'K' is the set of all DR3 participants 'k'. Where $\mathrm{TD}_{k,1341}$ is the *settlement amount* of *charge type* 1341 for the month for DR3 participant 'k'.	Monthly	Due *OPA*	0	N/A	N/A	N/A			*Former OPA* DR3 Contract. The DR3 program was last settled on the April 2015 settlement statements and invoice.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
1392	Demand Response 3 Availability Set-Off Balancing Amount	N/A	N/A	**<u>**CALCULATIONS FOR *CHARGE TYPE* 1392 ENDED ON APRIL 30, 2015.**</u> $\Sigma_K \mathrm{TD}_{k,1342}$ Where 'K' is the set of all DR3 participants 'k'. Where $\mathrm{TD}_{k,1342}$ is the *settlement amount* of *charge type* 1342 for the month for DR3 participant 'k'.	Monthly	Due *OPA*	0	N/A	N/A	N/A			*Former OPA* DR3 Contract. The DR3 program was last settled on the April 2015 settlement statements and invoice.
1393	Demand Response 3 Utilization Payment Balancing Amount	N/A	N/A	**<u>**CALCULATIONS FOR *CHARGE TYPE* 1393 ENDED ON APRIL 30, 2015.**</u> $\Sigma_K \mathrm{TD}_{k,1343}$ Where 'K' is the set of all DR3 participants 'k'. Where $\mathrm{TD}_{k,1343}$ is the *settlement amount* of *charge type* 1343 for the month for DR3 participant 'k'.	Monthly	Due *OPA*	0	N/A	N/A	N/A			Former *OPA* DR3 Contract. The DR3 program was last settled on the April 2015 settlement statements and invoice.
1394	Demand Response 3 Utilization Set-Off Balancing Amount	N/A	N/A	**<u>**CALCULATIONS FOR *CHARGE TYPE* 1394 ENDED ON APRIL 30, 2015.**</u>	Monthly	Due *OPA*	0	N/A	N/A	N/A			Former *OPA* DR3 Contract. The DR3 program was last settled on the April 2015

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				$\Sigma_K \mathrm{TD}_{k,1344}$ Where 'K' is the set of all DR3 participants 'k'. Where $\mathrm{TD}_{k,1344}$ is the *settlement amount* of *charge type* 1344 for the month for DR3 participant 'k'.									settlement statements and invoice.
1395	Demand Response 3 Planned Non-Event Set-Off Balancing Amount	N/A	N/A	**<u>CALCULATIONS FOR *CHARGE TYPE* 1395 ENDED ON APRIL 30, 2015.</u> $\Sigma_K \mathrm{TD}_{k,1345}$ Where 'K' is the set of all DR3 participants 'k'. Where $\mathrm{TD}_{k,1345}$ is the *settlement amount* of *charge type* 1345 for the month for DR3 participant 'k'.	Monthly	Due *OPA*	0	N/A	N/A	N/A			Former *OPA* DR3 Contract. The DR3 program was last settled on the April 2015 settlement statements and invoice.
1396	Demand Response 3 Meter Data Set-Off Balancing Amount	N/A	N/A	**<u>CALCULATIONS FOR *CHARGE TYPE* 1396 ENDED ON APRIL 30, 2015.</u> $\Sigma_K \mathrm{TD}_{k,1346}$ Where 'K' is the set of all DR3 participants 'k'.	Monthly	Due *OPA*	0	N/A	N/A	N/A			Former *OPA* DR3 Contract. The DR3 program was last settled on the April 2015 settlement statements and invoice.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				Where $TD_{k,1346}$ is the *settlement amount* of *charge type* 1346 for the month for DR3 participant 'k'.									
1397	Demand Response 3 Buy-Down Balancing Amount	N/A	N/A	**<u>CALCULATIONS FOR *CHARGE TYPE* 1397 ENDED ON APRIL 30, 2015.</u>** $\Sigma_K TD_{k,1347}$ Where 'K' is the set of all DR3 participants 'k'. Where $TD_{k,1347}$ is the *settlement amount* of *charge type* 1347 for the month for DR3 participant 'k'.	Monthly	Due *OPA*	0	N/A	N/A	N/A			*Former OPA* DR3 Contract. The DR3 program was last settled on the April 2015 settlement statements and invoice.
1398	Demand Response 3 Miscellaneous Balancing Amount	N/A	N/A	**<u>CALCULATIONS FOR *CHARGE TYPE* 1398 ENDED ON APRIL 30, 2015.</u>** $\Sigma_K TD_{k,1348}$ Where 'K' is the set of all DR3 participants 'k'. Where $TD_{k,1348}$ is the *settlement amount* of *charge type* 1348 for the month for DR3 participant 'k'.	Monthly	Due *OPA*	0	N/A	N/A	N/A			*Former OPA* DR3 Contract. The DR3 program was last settled on the April 2015 settlement statements and invoice.
1400	OPA Contract Adjustment	N/A	N/A	Manual entry based on the values submitted by the former *OPA* via On-	Monthly	Due *IESO*	13	N/A	N/A	N/A			Implementation details subject to

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
	Settlement Amount			line settlement form "Global Adjustment Amount Information", subject to Regulation.									government regulation
1401	Incremental Loss Settlement Credit	N/A	9.4.2.4	Calculated as per ancillary service contracts.	Hourly	Due *MP*	13	N/A	N/A	N/A			Reactive Support and Voltage Control Service
1402	Hourly Condense System Constraints Settlement Credit	N/A	9.4.2.4	Calculated as per ancillary service contracts.	Hourly	Due MP	13	N/A	N/A	N/A			Reactive Support and Voltage Control Service
1403	Speed-no-load Settlement Credit	N/A	9.4.2.4	Calculated as per ancillary service contracts.	Monthly	Due MP	13	N/A	N/A	N/A			Reactive Support and Voltage Control Service
1404	Condense Unit Start-up and OM&A Settlement Credit	N/A	9.4.2.4	Calculated as per ancillary service contracts.	Hourly	Due MP	13	N/A	N/A	N/A			Reactive Support and Voltage Control Service
1405	Hourly Condense Energy Costs Settlement Credit	N/A	9.4.2.4	Calculated as per ancillary service contracts.	Hourly	Due MP	13	N/A	N/A	N/A			Reactive Support and Voltage Control Service
1406	Monthly Condense Energy Costs Settlement Credit	N/A	9.4.2.4	Calculated as per ancillary service contracts.	Monthly	Due MP	13	N/A	N/A	N/A			Reactive Support and Voltage Control Service

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
1407	Condense Transmission Tariff Reimbursement Settlement Credit	N/A	9.4.2.4	Calculated as per ancillary service contracts.	Monthly	Due MP	13	N/A	N/A	N/A			Reactive Support and Voltage Control Service
1408	Condense Availability Cost Settlement Credit	N/A	9.4.2.4	Calculated as per ancillary service contracts.	Monthly	Due MP	13	N/A	N/A	N/A			Reactive Support and Voltage Control Service
1409	Monthly Condense System Constraints Settlement Credit	N/A	9.4.2.4	Calculated as per ancillary service contracts.	Monthly	Due MP	13	N/A	N/A	N/A			Reactive Support and Voltage Control Service
1410	Renewable Energy Standard Offer Program Settlement Amount	N/A	N/A	Manual entry based on the values submitted by *market participants* via On-line settlement forms: “Licenced Distributor Claims for the Renewable Energy Standard Offer Program” and “Embedded Distributor Claims for the Renewable Energy Standard Offer Program”.	Monthly	Due LDCs Either way	13	N/A	N/A	N/A			
1411	Clean Energy Standard Offer Program Settlement Amount	N/A	N/A	Manual entry based on the values submitted by *market participants* via future On-line settlement form “Clean Energy Standard Offer Program”.	Monthly	Due LDCs Either way	13	N/A	N/A	N/A			

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
1412	Feed-In Tariff Program Settlement Amount	N/A	N/A	Manual entry based on the values submitted by *market participants* via On-line settlement form "Feed-In Tariff Program".	Monthly	Due LDCs Either way	13	N/A	N/A	N/A			
1413	Renewable Generation Connection – Monthly Compensation Settlement Credit	N/A	N/A	Manual entry based on the values submitted by the OEB.	Monthly	Due LDCs Either way	13	N/A	N/A	N/A			Recipients, compensation amounts and other implementation details subject to OEB regulation.
1414	Hydroelectric Contract Initiative Settlement Amount	N/A	N/A	Manual entry based on the values submitted by the *market participant*.	Monthly	Due LDCs Either way	13	N/A	N/A	N/A			
1415	Conservation Assessment Recovery	N/A	N/A	$\Sigma_{\mathrm{H,M,}}\mathrm{TD}$ $\times (\Sigma_{H}{}^{\mathrm{M,T}}\mathrm{AQEW}_{\mathrm{k,h}}{}^{\mathrm{m,t}} / (\Sigma_{\mathrm{K,H}}{}^{\mathrm{M,T}}\mathrm{AQEW}_{\mathrm{k}}$ Where 'H' is the set of all *settlement hours* 'h' in the year 2009. Where 'K' is the set of all non-LDC load *market participants* 'k'. Where 'M' is the set of all *delivery points* 'm' of *market participant* 'k'.	Monthly	Due Non-LDC Load	13	N/A	N/A	N/A			Implementation details subject to government regulation.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				Where 'TD' equals the value assessed by the *OEB*.									
1416	Conservation and Demand Management – Compensation Settlement Credit	N/A	N/A	Manual entry based on the values submitted by the OEB and/or as stipulated by contracts held with the IESO.	Monthly	Due LDCs Either way	13	N/A	N/A	N/A			
1417	Daily Condense Energy Costs Settlement Credit	N/A	9.4.2.4	Calculated as per ancillary service contracts.	Monthly	Due MP	13	N/A	N/A	N/A			Reactive Support and Voltage Control Service
1418	Biomass Non-Utility Generation Contracts Settlement Amount	N/A	N/A	Manual entry based on the values submitted by *market participants* via Online *IESO*.	Monthly	Due LDCs Either way	13	N/A	N/A	N/A			
1419	Energy from Waste (EFW) Contracts Settlement Amount	N/A	N/A	Manual entry based on the values submitted by *market participants* via Online *IESO*.	Monthly	Due LDCs Either way	13	N/A	N/A	N/A			
1420	Ontario Electricity Support Program Settlement Amount	N/A	N/A	Manual entry based on the values submitted by *market participants* via Online *IESO*	Monthly	Due LDCs, USMPs and service providers	0	N/A	N/A	N/A			Implementation details subject to Ontario Regulation 314/15
1421	Capacity Agreement	N/A	N/A	Calculated as per capacity contracts.	Monthly	Either way	13	13	N/A	13			

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
	Settlement Credit												
1422	Capacity Agreement Penalty Settlement Amount	N/A	N/A	Calculated as per capacity contracts.	Monthly	Either way	13	13	N/A	13			
1423	Energy Sales Agreement Settlement Credit	N/A	N/A	Calculated as per energy sales contracts.	Monthly	Either way	13	13	N/A	13			
1424	Energy Sales Agreement Penalty Settlement Amount	N/A	N/A	Calculated as per energy sales contracts.	Monthly	Either way	13	13	N/A	13			
1425	Hydroelectric Standard Offer Program Settlement Amount	**N/A**	**N/A**	Manual Entry.	Monthly	Due LDCs either way	13	N/A	N/A	N/A			
1427	Non-Hydro Renewables Funding Amount	N/A	N/A	Manual entry as per Ontario Transfer Payment Agreement.	Monthly	Due IESO	13	N/A	N/A	N/A	January 1, 2021	March 31, 2022	Ontario Regulation 735/20
1450	OPA Contract Adjustment Balancing Amount	N/A	N/A	TD_{1400}	Monthly	Due *IESO*	0	N/A	N/A	N/A			Implementation details subject to government regulation

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
1451	Incremental Loss Offset Settlement Amount	N/A	9.4.2.4	Calculated as per ancillary service contracts.	Hourly	Due *IESO*	13	N/A	N/A	N/A			Reactive Support and Voltage Control Service
1457	Ontario Electricity Rebate Balancing Amount	N/A	N/A	ΣKTDk,9983 Where 'K' is the set of all *market participants* 'k'. Where TDk,9983 is the *settlement amount* of *charge type* 9983 for the month for *market participant* 'k'.	Monthly	Due Ministry of Energy	0	N/A	N/A	N/A			Implementation details subject to Ontario Regulation 363/16 and 364/16
1460	Renewable Energy Standard Offer Program Balancing Amount	N/A	N/A	$\Sigma_K \mathrm{TD}_{\mathrm{k},1410}$ Where 'K' is the set of all *market participants* 'k'. Where $\mathrm{TD}_{\mathrm{k},1410}$ is the total *settlement amount* of *charge type* 1410 for the month for *market participant* 'k'.	Monthly	Due *IESO*	0	N/A	N/A	N/A			
1461	Clean Energy Standard Offer Program Balancing Amount	N/A	N/A	$\Sigma_K \mathrm{TD}_{\mathrm{k},1411}$ Where 'K' is the set of all *market participants* 'k'.	Monthly	Due *IESO*	0	N/A	N/A	N/A			

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				Where $TD_{k,1411}$ is the total *settlement amount* of *charge type* 1411 for the month for *market participant* 'k'.									
1462	Feed-In Tariff Balancing Amount	N/A	N/A	$\Sigma_K TD_{k,1412}$ Where 'K' is the set of all *market participants* 'k'. Where $TD_{k,1412}$ is the total *settlement amount* of *charge type* 1412 for the month for *market participant* 'k'.	Monthly	Due *IESO*	0	N/A	N/A	N/A			
1463	Renewable Generation Connection – Monthly Compensation Settlement Debit	N/A	N/A	$\Sigma_K TD_{k,1413} \times (\Sigma_H {}^{M,T}AQEW_{k,h}{}^{m,t} + EGEI_k) / (\Sigma_{K,H} {}^{M,T}AQEW_{k,h}{}^{m,t} + \Sigma_K EGEI_k)$ Where 'H' is the set of all *settlement hours* 'h' in the month. Where 'K' is the set of all *market participants* 'k'. Where 'M' is the set of all *delivery points* 'm' of *market participant* 'k'. Where $TD_{k,1413}$ is the total *settlement amount* of *charge type* 1413 for the month for *market participant* 'k'.	Monthly	Due MPs	13	N/A	N/A	N/A			Cost recovery implementation details set out in Ontario Regulation 330/09

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
1464	Hydroelectric Contract Initiative Balancing Amount	N/A	N/A	$\Sigma_K \mathrm{TD}_{k,1414}$ Where 'K' is the set of all *market participants* 'k'. Where $\mathrm{TD}_{k,1414}$ is the total *settlement amount* of *charge type* 1414 for the month for *market participant* 'k'.	Monthly	Due IESO	0	N/A	N/A	N/A			
1465	Ontario Clean Energy Benefit (-10%) Program Balancing Amount	N/A	N/A	$\Sigma_K \mathrm{TD}_{k,9992}$ Where 'K' is the set of all *market participants* 'k'. Where $\mathrm{TD}_{k,9992}$ is the *settlement amount* of *charge type* 9992 for the month for *market participant* 'k'.	Monthly	Due Ministry of Energy	0	N/A	N/A	N/A			Implementation details subject to Ontario Regulation 495/10.
1466	Conservation and Demand Management – Compensation Balancing Amount	N/A		$\Sigma_K \mathrm{TD}_{k,1416}$ Where 'K' is the set of all *market participants* 'k'. Where $\mathrm{TD}_{k,1416}$ is the *settlement amount* of *charge type* 1416 for the month for *market participant* 'k'.	Monthly	Due *IESO*	0	N/A	N/A	N/A			
1467	Ontario Rebate for Electricity Consumers (8% Provincial Rebate)	N/A	N/A	ΣKTDk,9982 Where 'K' is the set of all *market participants* 'k'.	Monthly	Due Ministry of Energy	0	N/A	N/A	N/A			Implementation details subject to Ontario Regulation 363/16

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
	Balancing Amount			Where TDk,9982 is the *settlement amount* of *charge type* 9982 for the month for *market participant* 'k'.									
1468	Biomass Non-Utility Generation Contracts Balancing Amount	N/A	N/A	$\Sigma_K \mathrm{TD}_{\mathrm{k},1418}$ Where 'K' is the set of all *market participants* 'k'. Where $\mathrm{TD}_{\mathrm{k},1418}$ is the total *settlement amount* of *charge type* 1418 for the month for *market participant* 'k'.	Monthly	Due *IESO*	0	N/A	N/A	N/A			
1469	Energy from Waste (EFW) Contracts Balancing Amount	N/A	N/A	$\Sigma_K \mathrm{TD}_{\mathrm{k},1419}$ Where 'K' is the set of all *market participants* 'k'. Where $\mathrm{TD}_{\mathrm{k},1419}$ is the total *settlement amount* of *charge type* 1419 for the month for *market participant* 'k'	Monthly	Due *IESO*	0	N/A	N/A	N/A			
1470	Ontario Electricity Support Program Balancing Amount	N/A	N/A	**** *CHARGE TYPE* 1470 REPLACED BY *CHARGE TYPE* 2470 EFFECTIVE FEBRUARY 1, 2018 **** $\sum_H {}^{\mathrm{M,T}}\left(\mathrm{AQEW}_{\mathrm{k,h}}{}^{\mathrm{m,t}} + \mathrm{EGEI}_k\right) \times \mathrm{TP}$	Monthly	Due IESO	13	N/A	N/A	N/A			Implementation details subject to Ontario Regulation 314/15. TP rate subject to OEB regulation.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				Where 'H' is the set of all *settlement hours* 'h' in the month. Where 'T' is the set of all *metering intervals* 't' in the set of all *settlement hours* 'H'.									
1471	Capacity Agreement Balancing Amount	N/A	N/A	$\Sigma_K \mathrm{TD}_{\mathrm{k},1421}$ Where 'K' is the set of all *market participants* 'k'. Where $\mathrm{TD}_{\mathrm{k},1421}$ is the total *settlement amount* of *charge type* 1421 for the month for *market participant* 'k'	Monthly	Either way	0	N/A	N/A	N/A			
1472	Capacity Agreement Penalty Balancing Amount	N/A	N/A	$\Sigma_K \mathrm{TD}_{\mathrm{k},1422}$ Where 'K' is the set of all *market participants* 'k'. Where $\mathrm{TD}_{\mathrm{k},1422}$ is the total *settlement amount* of *charge type* 1422 for the month for *market participant* 'k'	Monthly	Either way	0	N/A	N/A	N/A			
1473	Energy Sales Agreement Balancing Amount	N/A	N/A	$\Sigma_K \mathrm{TD}_{\mathrm{k},1423}$ Where 'K' is the set of all *market participants* 'k'. Where $\mathrm{TD}_{\mathrm{k},1423}$ is the total *settlement amount* of *charge type* 1423 for the month for *market participant* 'k'	Monthly	Either way	0	N/A	N/A	N/A			

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
1474	Energy Sales Agreement Penalty Balancing Amount	N/A	N/A	$\Sigma_K \mathrm{TD}_{\mathrm{k},1424}$ Where 'K' is the set of all *market participants* 'k'. Where $\mathrm{TD}_{\mathrm{k},1424}$ is the total *settlement amount* of *charge type* 1424 for the month for *market participant* 'k'	Monthly	Either way	0	N/A	N/A	N/A			
1475	Hydroelectric Standard Offer Program Balancing Amount	N/A	N/A	ΣKTDk,1425 Where 'K' is the set of all *market participants* 'k'. Where TDk,1425 is the total *settlement amount* of *charge type* 1425 for the month for *market participant* 'k'.	Monthly	Due IESO	0	N/A	N/A	N/A			
1477	COVID-19 Energy Assistance Program (CEAP) Settlement Amount	N/A	N/A	Manual entry based on the values submitted via the relevant on-line settlement form "COVID-19 Energy Assistance Program" for residential consumers.	Monthly	Due LDCs and USMPs	0	N/A	N/A	N/A			Implementation details subject to OEB order EB-2020-0186 and EB-2020-0163
1487	Non-Hydro Renewables Funding Balancing Amount	N/A	N/A	TD_{1427}	Monthly	Due IESO	13	N/A	N/A	N/A	January 1, 2021	March 31, 2022	Ontario Regulation 735/20
1500	Day-Ahead Production Cost Guarantee	DA_PCG_COMP1	9.4.7D.4	$\sum^T$ (Component 1 – Component1 Clawback)	Hourly	Either Way	13	N/A	N/A	N/A			**Component 1** applies to

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
	Payment – Component 1 and Component 1 Clawback			**Component 1:** $-1 \times OP(EMP_h^{m,t}, MIN(DA_DQSI_{k,h}^{m,t}, DQSI_{k,h}^{m,t}, AQEI_{k,h}^{m,t}), DA_BE) + DA_SNLC_{k,h}^{m}/12$ **Component 1 Clawback:** $-1 \times OP(EMP_h^{m,t}, MIN(MLP_{k,h}^{m,t}, AQEI_{k,h}^{m,t}), DA_BE) + DA_SNLC_{k,h}^{m}/12$ Where: T is the set of metering intervals in the settlement hour h. 'OP' is the operating profit function defined in *IESO market rules* Section 9.3.8B.2. For a combustion turbine resource associated to a pseudo unit: **Component 1:** $-1 \times OP(EMP_h^{m,t}, MIN(DA_DQSI_{k,h}^{m,t}, DQSI_{k,h}^{m,t},$									Variants 1, 2 and 3. **Component 1 Clawback** applies to Variant 2 only. For a description of Production Cost Guarantee Variants, see Market Rules 9.4.7D.2.1

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				$AQEI_{k,h}^{m,t}$), $DIPC_{k,h}^{m,t}$) + $(DA_SNLC_{k,h}^{m}/12) * (1 - PST_{k,h}^{p,t})$ **Component 1 Clawback:** $-1 \times OP(EMP_{h}^{m,t}, MIN(MLP_CONS_{k,h}^{m,t}, AQEI_{k,h}^{m,t}), DIPC_{k,h}^{m,t}) + (DA_SNLC_{k,h}^{m}/12) * (1 - PST_{k,h}^{p,t})$ For a steam turbine resource associated to a pseudo unit: **Component 1:** $-1 \times OP(EMP_{h}^{m,t}, MIN(DIGQ_{k,h}^{m,t}, DQSI_{k,h}^{m,t}, AQEI_{k,h}^{m,t}), DIPC_{k,h}^{m,t}) + (DA_SNLC_{k,h}^{m}/12) * PST_{k,h}^{p,t}$ **Component 1 Clawback:** $-1 \times OP(EMP_{h}^{m,t}, MIN(MLP_CONS_{k,h}^{m,t}, AQEI_{k,h}^{m,t}), DIPC_{k,h}^{m,t}) + (DA_SNLC_{k,h}^{m}/12) * PST_{k,h}^{p,t}$									
1501	Day-Ahead Production Cost Guarantee	DA_PCG_COMP2	9.4.7D.4	$\sum^{T}(XDA_BE_{k,h}^{m,t} - MAX(0, XBE_{k,h}^{m,t}))$ Where:	Hourly	Either Way	13	N/A	N/A	N/A			**Component 2** applies to Variants 1, 2 and 3.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
	Payment – Component 2			T is the set of metering intervals in the settlement hour h. $XDA_BE_{k,h}^{m,t} = (-1) * [OP(EMP_h^{m,t}, min(DA_DQSI_{k,h}^{m,t}, OPCAP_{k,h}^{m,t}), DA_BE) – OP(EMP_h^{m,t}, min(DA_DQSI_{k,h}^{m,t}, OPCAP_{k,h}^{m,t}, max(DQSI_{k,h}^{m,t}, AQEI_{k,h}^{m,t})), DA_BE)]$ $XBE_{k,h}^{m,t} = (-1) * [OP(EMP_h^{m,t}, min(DA_DQSI_{k,h}^{m,t}, OPCAP_{k,h}^{m,t}), BE) – OP(EMP_h^{m,t}, min(DA_DQSI_{k,h}^{m,t}, OPCAP_{k,h}^{m,t}, max(DQSI_{k,h}^{m,t}, AQEI_{k,h}^{m,t})), BE)]$ Where: 'OP' is the operating profit function defined in *IESO market rules* Section 9.3.8B.2. $EMP_h^{m,t} = 0$. For a combustion turbine and a steam turbine resources associated to a pseudo unit: DA_BE is replaced with $DIPC_{k,h}^{m,t}$.									For a description of Production Cost Guarantee Variants, see Market Rules 9.4.7D.2.1

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				For a steam turbine resource associated to a pseudo unit: $DA_DQSI_{k,h}^{m,t}$ is replaced with the $DIGQ_{k,h}^{m,t}$									
1502	Day-Ahead Production Cost Guarantee Payment – Component 3 and Component 3 Clawback	DA_PCG_COMP3	9.4.7D.4	$\sum^{T}(-1) *$ (Component 3 + Component 3 Clawb Where: T is the set of metering intervals in the settlement hour h. For Component 3, the six scenarios of the possible orderings of the generator's DA_DQSI, DQSI and MQSI are as follows: 1. DQSI >= MQSI >= DA_DQSI 2. MQSI >= DQSI >= DA_DQSI 3. DQSI > DA_DQSI > MQSI 4. MQSI > DA_DQSI > DQSI 5. DA_DQSI >= DQSI > MQSI 6. DA_DQSI >= MQSI > DQSI	Hourly	Either Way	13	N/A	N/A	N/A			**Component 3** applies to Variants 1, 2 and 3. **Component 3 Clawback** applies to Variant 2 only. For a description of Production Cost Guarantee Variants, see Market Rules 9.4.7D.2.1

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				Component 3: Component 3 is calculated when: the CMSC for energy ($TD_{k,h,105}^{m,t}$) for the same metering interval is a value other than zero; and the mathematical sign of (DQSI-MQSI) is equal to the mathematical sign of (AQEI-MQSI). Scenario 1 and 2: 0 Scenario 3: $OP(EMP_h^{m,t}, MQSI_{k,h}^{m,t}, BE) – MAX(OP(EMP_h^{m,t}, DA_DQSI_{k,h}^{m,t}, BE), OP(EMP_h^{m,t}, AQEI_{k,h}^{m,t}, BE))$ Scenario 4: $OP(EMP_h^{m,t}, DA_DQSI_{k,h}^{m,t}, BE) – MAX(OP(EMP_h^{m,t}, DQSI_{k,h}^{m,t}, BE), OP(EMP_h^{m,t}, AQEI_{k,h}^{m,t}, BE))$									

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				Scenario 5 and 6: $TD_{k,h,105}^{m,t}$ Refer to Market Rules for a description of Scenarios 1 through 6. **Component 3 Clawback:** Component 3 Clawback is calculated when: the event is a constrained-on event (i.e. Scenarios 3 and 5); the *minimum loading point* is greater than the real-time unconstrained schedule; and Component 3 ($PCG_COMP3_{k,h}^{m,t}$) for the same interval is a value other than zero. $MAX(OP(EMP_h^{m,t}, MLP_{k,h}^{m,t}, BE), OP(EMP_h^{m,t}, AQEI_{k,h}^{m,t}, BE)) – OP(EMP_h^{m,t}, MQSI_{k,h}^{m,t}, BE)$ For combustion turbine resources associated to a pseudo unit:									

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				DA_BE is replaced with $DIPC_{k,h}^{m,t}$; and MLP is replaced with MLP_CONS. For steam turbine resources associated to a pseudo unit: DA_BE is replaced with $DIPC_{k,h}^{m,t}$, MLP is replaced with MLP_CONS, and $DA_DQSI_{k,h}^{m,t}$ is replaced with the $DIGQ_{k,h}^{m,t}$. Where 'OP' is the operating profit function defined in *IESO market rules* Section 9.3.8B.2.									
1503	Day-Ahead Production Cost Guarantee Payment – Component 4	DA_PCG_ COMP4	9.4.7D.4	$\sum^{T}((-1) \times [OP(PROR_{r1,h}^{m,t}, 30R_SQROR_{r1,k,h}^{m,t},$	Hourly	Either Way	13	N/A	N/A	N/A			**Component 4** applies to Variants 1, 2 and 3. For a description of Production Cost Guarantee Variants, see Market Rules 9.4.7D.2.1

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				$+ OP\left(\begin{matrix}PROR_{r2,h}{}^{m,t},\\ 10NS_SQROR_{r2,k,h}{}^{m,t},\\ BR_{r2,k,h}{}^{m,t}\end{matrix}\right)$ $+ OP\left(\begin{matrix}PROR_{r3,h}{}^{m,t},\\ 10S_SQROR_{r3,K,h}{}^{m,t},\\ BR_{r3,k,h}{}^{m,t}\end{matrix}\right)])$ Where T is the set of metering intervals in the settlement hour h. 'OP' is the operating profit function defined in *IESO market rules* Section 9.3.8B.2. r1 = 30-minute operating reserve r2 = 10-minute non-spinning operating reserve r3 = 10-minute spinning operating reserve $30R_SQROR_{r1,k,h}{}^{m,t} = MAX[0,MIN(DA_DQSI_{k,h}{}^{m,t} - MQSI_{k,h}{}^{m,t}, SQROR_{r1,k,h}{}^{m,t})]$									

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				$10NS_SQROR_{r2,k,h}^{m,t} = MAX[0,MIN(DA_DQSI_{k,h}^{m,t} – MQSI_{k,h}^{m,t} - 30R_SQROR_{r1,k,h}^{m,t}, SQROR_{r2,k,h}^{m,t})]$ $10S_SQROR_{r3,k,h}^{m,t} = MAX[0,MIN(DA_DQSI_{k,h}^{m,t} – MQSI_{k,h}^{m,t} - 30R_SQROR_{r1,k,h}^{m,t} – 10NS_SQROR_{r2,k,h}^{m,t}, SQROR_{r3,k,h}^{m,t})]$ For combustion turbine resources and steam turbine resources associated to a pseudo unit: $DA_DQSI_{k,h}^{m,t}$ is replaced with the $DIGQ_{k,h}^{m,t}$									
1504	Day-Ahead Production Cost Guarantee Payment – Component 5	DA_PCG_ COMP5	9.4.7D.4	If first hour of the DACP start event is not HE24, then the start-up cost is calculated as follows: Scenario 1 (achieves MLP before the 7th interval): $DA_SUC_{k,h}^{m}$ Scenario 2 (achieves MLP between the 7th and 18th interval):	Hourly	Due *IESO*	13	N/A	N/A	N/A			**Component 5** applies to Variant 1 only. For a description of Production Cost Guarantee Variants, see Market Rules 9.4.7D.2.1

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				$DA_SUC_{k,h}^{m} – (DA_SUC_{k,h}^{m} \times 1/12 \times SUC_INT)$ Where SUC_INT is the number of 5-minute intervals between and including Interval 7 and 18 the *market participant* takes to achieve MLP Scenario 3 (achieves MLP after the start of the 18th interval): 0 For a combustion turbine resource associated to a pseudo unit: Scenario 1 (achieves MLP before the 7th interval): $DA_SUC_{k,h}^{p} * (1 – PST_{k,h}^{p,t})$ Scenario 2 (achieves MLP between the 7th and 18th interval): $DA_SUC_{k,h}^{p} * MLP_MF * (1 – PST_{k,h}^{p,t})$									

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				Scenario 3 (achieves MLP after the start of the 18th interval): 0 Where MLP_MF = 1/12 * (12 - SUC_INT) For a steam turbine resource associated to a pseudo unit: Scenario 1 (achieves MLP before the 7th interval): $DA_SUC_{k,h}^{p}$ * ($PST_{k,h}^{p,t}$) Scenario 2 (achieves MLP between the 7th and 18th interval): $DA_SUC_{k,h}^{p}$ * MLP_MF * ($PST_{k,h}^{p,t}$) Scenario 3 (achieves MLP after the start of the 18th interval): 0. If first hour of the DACP start event is HE24 and the resource has not achieved MLP before Interval 12,									

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				then the start-up cost is calculated as follows: $DA_SUC_{k,h}^{m} * 50\%$ For a combustion turbine resource associated to a pseudo unit: $DA_SUC_{k,h}^{m} * (1 - PST_{k,h}^{p,t}) * 50\%$ For a steam turbine resource associated to a pseudo unit: $DA_SUC_{k,h}^{m} * (PST_{k,h}^{p,t}) * 50\%$									
1505	Day-Ahead Production Cost Guarantee Reversal		9.4.7D.6	For each DACP start event $If \sum_{H,C} TD_{k,h,c} < 0$ Then $\sum_{H,C} TD_{k,h,c}$ Else 0 Where: 'C' is the set of the following charge types 'c' as follows: **1500, 1501, 1502, 1503, 1504**	Hourly	Due MP	13	N/A	N/A	N/A			

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				'H' is the set of all *settlement hours* 'h' in the DACP start event.									
1510	Day-Ahead Generator Withdrawal Charge	DA_GWC	9.3.8F.2	The Day-Ahead Generator Withdrawal Charge is calculated as follows: If notification of the withdrawal is received 4 or more hours prior to first withdrawal hour: $\mathrm{MIN}(0,\sum_{i=1}^{n}(-1) * \mathrm{OP}([\mathrm{MIN}(\mathrm{PD_EMP}_h^{m,t}, \mathrm{EMP}_h^{m,t}), \mathrm{MLP}_{k,h}^{m,t}, \mathrm{DA_BE}_{k,h}^{m,t}))$ Where: n is the set of all *metering intervals* 't' in *settlement hour* 'h' for the total number of hours with a committed day-ahead schedule for the DACP start event that are withdrawn If notification of the withdrawal is received less than 4 hours prior to first withdrawal hour: $\mathrm{MIN}(0,\sum_{i=1}^{n}(-1) * \mathrm{OP}(\mathrm{EMP}_h^{m,t}, \mathrm{MLP}_{k,h}^{m,t}, \mathrm{DA_BE}_{k,h}^{m,t})$	Daily	Due *IESO*	13	N/A	N/A	N/A			

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				Where: n is the set of all *metering intervals* 't' in *settlement hour* 'h' for the total number of hours with a committed day-ahead schedule for the DACP start event that are withdrawn For resources associated to a pseudo unit, the DA_BE is replaced with $DIPC_{k,h}^{m,t}$; and the MLP is replaced with MLP_CONS.									
1550	Day-Ahead Production Cost Guarantee Recovery Debit		9.4.8.1.12	$\sum_{H,c}{}^{M,T} TD_{k,h,c} \times [(AQEW_{k,h}{}^{m,t} + SQEW_{k,h}{}^{i,t}) / \sum_{k}{}^{M,T} (AQEW_{k,h}{}^{m,t} + SQEW_{k,h}{}^{i,t})]$ Where: 'C' is the set of the following charge types 'c' as follows: **1500, 1501, 1502, 1503, 1504, 1505** 'K' is the set of all market participants 'k'. 'M' is the set of all delivery points 'm' and intertie metering points 'i'.	Daily	Due *IESO*	13	N/A	0	13			

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				'H' is the set of all *settlement hours* 'h' in the day. 'T' is the set of 12 *metering intervals* 't' during *settlement hour* 'h'.									
1560	Day-Ahead Generator Withdrawal Rebate		9.4.8.2.14	$\sum_{H,c}{}^{M,T}TD_{k,h,c} \times [(AQEW_{k,h}{}^{m,t} + SQEW_{k,h}{}^{i,t}) / \sum_{K}{}^{M,T}(AQEW_{k,h}{}^{m,t} + SQEW_{k,h}{}^{i,t})]$ Where: 'c' is *charge type* 1510. 'K' is the set of all market participants 'k'. 'M' is the set of all delivery points 'm' and intertie metering points 'i'. 'H' is the set of all *settlement hours* 'h' in the day. 'T' is the set of 12 *metering intervals* 't' during *settlement hour* 'h'.	Daily	Due MP	13	N/A	0	13			
1600	Forecasting Service Settlement Amount	N/A	9.1.1.2.16, 9.4.7G , 9.4.7G.1, 9.4.8.1.16, 9.6.3.17, 9.6.11.5	Manual entry based on the values submitted by the forecasting entity.	Monthly	Due MP	13	N/A	N/A	N/A			

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
1650	Forecasting Service Balancing Amount	N/A	9.1.1.2.16, 9.4.7G , 9.4.7G.1, 9.4.8.1.16, 9.6.3.17, 9.6.11.5	$= \sum_{H,C}{}^{M,T} TD_{h,c} \times [(AQEW_{k,h}{}^{m,t} + SQEW_{k,h}{}^{i,t}) / \sum_{k,H}{}^{M,T} (AQEW_{k,h}{}^{m,t} + SQEW_{k,h}{}^{i,t})]$ Where 'C' is charge type 'c' **1600.** Where 'H' is the set of all *settlement hours* 'h' in the month. Where 'T' is the set of all *metering intervals* 't' in the set of all *settlement hours* 'H'.	Monthly	Due *IESO*	13	N/A	0	13			
1750	Dispute Resolution Balancing Amount (Market)	N/A	3.2.7 and 9.6.8.5 (if applicable)	∑H,cM,T TDh,(700) × [(AQEWk,hm,t + SQEWk,hi,t) / ∑k,HM,T (AQEWk,hm,t + SQEWk,hi,t)], where applicable Where 'H' is the set of all settlement hours 'h' in the month. Where 'T' is the set of all metering intervals 't' in the set of all settlement hours 'H'.	Monthly	Due MP	13	N/A	0	13			
1753	MOE - Rural and Remote Settlement Debit	N/A	N/A	Manual entry based on: (1) the values submitted via on-line settlement form "Rural or Remote Rate Protection (RRRP) – Fixed Rate Credit";	Monthly	Due Ministry of Energy	N/A	N/A	N/A	N/A			Implementation details subject to government and OEB regulations.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
2148	Class B Global Adjustment Prior Period Correction Settlement Amount	N/A	N/A	Manual entry based on post-final changes to input data for charge type 148	Monthly	Due MP	13	N/A	N/A	N/A			
2470	MOE - Ontario Electricity Support Program Balancing Amount	N/A	N/A	ΣKTDk,1420 Where 'K' is the set of all *market participants* 'k'. Where TDk,1420 is the *settlement amount* of *charge type* 1420 for the month for *market participant* 'k'.	Monthly	Due Ministry of Energy	0	N/A	N/A	N/A			Implementation details subject to government and OEB regulations.
6000	Ontario Fair Hydro Plan - Regulatory Asset Transfer Amount	N/A	N/A	Manual Entry	Monthly	Due Financing Entity	N/A	N/A	N/A	N/A			Implementation details subject to government regulations
6050	Ontario Fair Hydro Plan - Regulatory Asset Transfer Balancing Amount	N/A	N/A	Manual Entry	Monthly	Due IESO	N/A	N/A	N/A	N/A			Implementation details subject to government regulations

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
6147	Class A Global Adjustment Deferral Recovery Amount	N/A	N/A	$MDCAA \times (PDF_{k,m,d} / \sum_K PDF_{k,m,d})$ Where 'K' is the set of all *market participants* 'k'.	Monthly	Due IESO	13	N/A	N/A	N/A	January 1. 2021	December 31, 2021	Ontario Regulation 429/04
6148	Class B Global Adjustment Deferral Recovery Amount	N/A	N/A	$CBRR \times CBMP_k$ Where: $CBRR = MDCBA / (\text{Class B Load} - \sum_K RPPVA_k)$ Class B Load = $(\Sigma_{K,H}^{M,T} AQEW_{k,h}^{m,t} + \Sigma_K EGEI_k - \Sigma_K EEQ - \Sigma_K GA_AQEW_{g,k,h,M}^{m,t} - \Sigma_K PGS_{h,M} - \Sigma_K U_k)$ For Fort Frances Power Corporation Distribution Inc.: $CBMP_k = \Sigma_H^{M,T} AQEW_{k,h}^{m,t} + EGEI_k - EEQ - RPPVA_k$	Monthly	Due IESO	13	N/A	N/A	N/A	January 1. 2021	December 31, 2021	Ontario Regulation 429/04

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				For other applicable Class B market participants or licensed distributors that are also market participants : $CBMP_k = \Sigma_H^{M,T} AQEW_{k,h}^{m,t} + EGEI_k - GA_AQEW_{g,k,h,M}^{m,t} - PGS_{h,M} - RPPVA_k$ Where 'H' is the set of all *settlement hours* 'h' in the month. Where 'K' is the set of all *market participants* 'k'. Where 'M' is the set of all *delivery points* 'm' of *market participant* 'k'.									
9147	Class A Global Adjustment Smoothing Balancing Amount	N/A	N/A	$\Sigma_K TD_{k,6147}$ Where 'K' is the set of all *market participants* 'k'. Where $TD_{k,6147}$ is the *settlement amount* of *charge type* 6147 for the month for *market participant* 'k'.	Monthly	Due IESO	0	N/A	N/A	N/A	April 1, 2020	December 31, 2021	Ontario Regulation 429/04

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
9148	Class B Global Adjustment Smoothing Balancing Amount	N/A	N/A	$\Sigma_K TD_{k,6148}$ Where 'K' is the set of all *market participants* 'k'. Where $TD_{k,6148}$ is the *settlement amount* of *charge type* 6148 for the current month for *market participant* 'k'.	Monthly	Due IESO	0	N/A	N/A	N/A	April 1, 2020	December 31, 2021	Ontario Regulation 429/04
9920	Adjustment Account Credit	AAC	9.6.18.6	$AAD \times \sum_H{}^{M,T}[(AQEW_{k,h}{}^{m,t} + SQEW_{k,h}{}^{i,t}) / \sum_{K,H}{}^{M,T} (AQEW_{k,h}{}^{m,t} + SQEW_{k,h}{}^{i,t})]$ Where 'H' is the set of all s*ettlement hours* 'h' in the *billing periods* immediately preceding the current *billing period*, as determined by *IESO Board.* Where 'T' is the set of all *metering intervals* 't' in the set of all *settlement hours* 'H'. Where 'M' is the set of all *delivery points* 'm' and *intertie metering points* 'i'	Monthly (when applicable)	Due MP	13	N/A	0	13			The *billing period* is defined in Market Manual 5: Settlements Part 5.5: Physical Markets Settlement Statements, section 1.6.30

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				Where 'K' is the set of all *market participants* 'k'.									
9980	Smart Metering Charge	N/A	N/A	Manual entry based on the values submitted by the *Smart Metering Entity*.	Monthly	Due *IESO*	13	N/A	N/A	N/A			Subject to Ontario Regulation 453/06 and the applicable OEB rate order.
9982	Ontario Rebate for Electricity Consumers (8% Provincial Rebate) Settlement Amount	N/A	N/A	Manual entry based on: (1) the values submitted via on-line settlement form "Ontario Rebate for Electricity Consumers (OREC) – LDC and USMP"; and (2) 8 per cent of the base invoice amount for *market participant consumers* who have an eligible account with the *IESO*	Monthly	Due LDCs, Unit Sub-Meter Providers and eligible MPs	0	N/A	N/A	N/A			Implementation details subject to Ontario Regulation 363/16
9983	Ontario Electricity Rebate Settlement Amount	N/A	N/A	Manual entry based on: (1) the values submitted via on-line settlement forms "Ontario Electricity Rebate (OER) – LDC & USMP";	Monthly	Due LDCs, Unit Sub-Meter Providers and eligible MPs	0	N/A	N/A	N/A			Implementation details subject to Ontario Regulation 363/16 and 364/16

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
				and (2) 33.2 per cent of the base invoice amount for *market participant consumers* who have an eligible account with the *IESO*									
9984	COVID-19 Energy Assistance Program (CEAP) Balancing Amount	N/A	N/A	ΣKTDk,1477 Where 'K' is the set of all market participants 'k' Where TDk,1477 is the settlement amount of charge type 1477 for the month for market participant 'k'.	Monthly	Due Ministry of Energy	0	N/A	N/A	N/A			Implementation details subject to OEB order EB-2020-0186 and EB-2020-0163
9990	IESO Administration Charge	N/A	9.4.5.1	$\sum_{H}^{M,T}(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t} + EGEI_{k}) \times TP$ Where 'H' is the set of all *settlement hours* 'h' in the month. Where 'T' is the set of all *metering intervals* 't' in the set of all *settlement hours* 'H'.	Monthly	Due *IESO*	13	N/A	0	13			TP rate subject to OEB regulation.
9992	Ontario Clean Energy Benefit (-10%) Program	N/A	N/A	Manual entry based on the values submitted by *market participants* via on-line settlement forms "Ontario	Monthly	Due LDCs and Unit Sub-Meter	0	N/A	N/A	N/A			Implementation details subject to Ontario

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow (See Note at Beginning of this Section)	HST Tax Treatment within Ontario (%)	HST Tax Treatment for U.S., Manitoba, and Quebec Generation (%)	HST Tax Treatment for U.S. Load (%)	HST Tax Treatment for Manitoba and Quebec Load (%)	Effective Start Trading Day	Effective End Trading Day	Comments
	Settlement Amount			Clean Energy Benefit (−10%) – LDC" and "Ontario Clean Energy Benefit (−10%) – Unit Sub-Meter Provider".		Providers Either way							Regulation 495/10.
9996	Recovery of Costs	N/A	Ch. 2, Appendix 3.4	Manual entry as per Chapter 2, Appendix 3.4	Monthly	Due *IESO*	13	N/A	N/A	N/A			

2.3 Rounding Conventions – by Settlement Variable

2.3.1 Key to the Table of Rounding Conventions for Individual Settlement Variables

Column Name	Description
Variable referenced in Section 2.1	This column provides the name of the variable listed in Section 2.1.
Data Description	The short name of the variable in question.
Number of decimal places (values published by upstream systems)	If this variable is available to *market participants* via another system besides *settlements*, this number of significant digits to the right of the decimal place in the published value. NOTE: "published" does not necessarily mean a public report or a report available to all *market participants*. E.g. *metering data* from the *metering database*.
Number of significant digits to the right of the decimal (values received by CRS)	This column discloses the accuracy of a settlement variable received by the *IESO* settlements system via an upstream system OR manually entered as the case may be.
Number of significant digits to the right of the decimal (externally passed from CRS in settlement statements or data files)	This column discloses the accuracy of a settlement variable appearing on a *settlement statement*. **NOTE: This should NOT be confused with the number of decimal places allowable in some columns on the *settlement statements* and data files as set out in, "Format Specification for Settlement Statements and Data Files."**
Comments	Any comments as to the availability of such variables. In some cases, variables are not made available to *market participants* via upstream systems and are noted as such. In other instances variables are not published in a report but are communicated in participant-specific messages (e.g. *bid*/*offer* confirmation).

Variable referenced in Section 2.1	Data Description	Number of DECIMAL PLACES (values published by upstream systems)	MAXIMUM Number of SIGNIFICANT DIGITS to the right of the decimal (values received by CRS)	MAXIMUM Number of SIGNIFICANT DIGITS to the right of the decimal (externally passed from CRS in settlement statements or data files)	Comments
AAD	Adjustment Account Disbursement	N/A	2	3	• Not published in upstream IESO systems
$AQEI_{k,h}^{m,t}$	Allocated Quantity of Energy Injected	2	3	3	• RMS presentation is in units of KW to TWO decimal places. • Unit change to MW to 3 decimal places occurs prior to transfer to CRS.
$AQEW_{k,h}^{m,t}$	Allocated Quantity of Energy Withdrawn	2	3	3	• RMS presentation is in units of KW to TWO decimal places. • Unit change to MW to 3 decimal places occurs prior to transfer to CRS.
$AQOR_{r,k,h}^{m,t}$	Allocated Quantity of Operating Reserve	1	1	1	• See SQROR.
BE	Energy Offers	N/A	1	1	• Not published via upstream *IESO* systems. • Confirmations passed to *market participants as bids/offers* ("*dispatch data*") are received.

Variable referenced in Section 2.1	Data Description	Number of DECIMAL PLACES (values published by upstream systems)	MAXIMUM Number of SIGNIFICANT DIGITS to the right of the decimal (values received by CRS)	MAXIMUM Number of SIGNIFICANT DIGITS to the right of the decimal (externally passed from CRS in settlement statements or data files)	Comments
BL	Energy Bids	N/A	1	1	• Not published via upstream *IESO* systems. • Confirmations passed to *market participants as bids/offers* ("*dispatch data*") are received.
BR_r	Operating Reserve Offers	N/A	1	1	• Not published via upstream *IESO* systems. • Confirmations passed to *market participants as bids/offers* ("*dispatch data*") are received.
$BCQ_{s,k,h}^{m,t}$	Physical Bilateral Contract Quantity of Energy bought	N/A	1 or 3	1 or 3	• Not published via upstream *IESO* systems. • *Physical Bilateral Contract Data* is provided to the *IESO* by the selling market participant. • Accuracy driven by the submission at the MIM interface and the method used (i.e. absolute quantities vs. 100% of PBC).

Variable referenced in Section 2.1	Data Description	Number of DECIMAL PLACES (values published by upstream systems)	MAXIMUM Number of SIGNIFICANT DIGITS to the right of the decimal (values received by CRS)	MAXIMUM Number of SIGNIFICANT DIGITS to the right of the decimal (externally passed from CRS in settlement statements or data files)	Comments
$BCQ_{k,b,h}^{m,t}$	Physical Bilateral Contract Quantity of Energy sold	N/A	1 or 3	1 or 3	• Not published via upstream *IESO* systems. • *Physical Bilateral Contract Data* is provided to the *IESO* by the *selling market participant.* • Accuracy driven by the submission at the MIM interface and the method used (i.e. absolute quantities vs. 100% of *PBC*).
$CACP^{z}$	Capacity Auction Clearing Price	2	2	2	• Published in post-auction report.
$CACP^{z}_{h}$	Hourly Capacity Auction Clearing Price	N/A	2	2	• Not published via upstream *IESO* systems.
$CAEO^{m}_{h,k}$	Capacity Auction Energy Offer	N/A	1	1	• Not published via upstream IESO system
$CARC_{k^m}$	Capacity Auction Registered Capability	N/A	3	3	• Not published via upstream IESO system
$CBOC^{m}_{k}$	Buy-Out Capacity	N/A	3	3	• Not published via upstream *IESO* systems.
$CCO^{m}_{k,h}$	Capacity Obligation (MW)	1	3	3	• Published in private post-auction report.
CGC	Combined Guaranteed Costs	N/A	2	2	• Not published via upstream *IESO* systems.

Variable referenced in Section 2.1	Data Description	Number of DECIMAL PLACES (values published by upstream systems)	MAXIMUM Number of SIGNIFICANT DIGITS to the right of the decimal (values received by CRS)	MAXIMUM Number of SIGNIFICANT DIGITS to the right of the decimal (externally passed from CRS in settlement statements or data files)	Comments
$CICAP^{m}_{k}$	Capacity Auction *Cleared ICAP*				•
$CNPF_{tm}$	Capacity Auction Non-Performance Factor	N/A	1	1	• Not published via upstream *IESO* systems.
$DA_BE_{k,h}^{i,t}$	*Energy Offer* submitted into the *schedule of record*	N/A	N/A	N/A	• Not published via upstream *IESO* systems. • Confirmations passed to *market participants* as *bids*/*offers* ("*dispatch data*") are received.
$DA_BE_{k,h}^{m,t}$	*Energy Offer* submitted into the *schedule of record at a delivery point*	N/A	N/A	N/A	• Not published via upstream *IESO* systems. • Confirmations passed to *market participants* as *bids*/*offers* ("*dispatch data*") are received.
$DA_BL_{k,h}^{i,t}$	*Energy Bids* submitted into the *schedule of record*	N/A	N/A	N/A	• Not published via upstream *IESO* systems. • Confirmations passed to *market participants* as *bids*/*offers* ("*dispatch data*") are received.

Variable referenced in Section 2.1	Data Description	Number of DECIMAL PLACES (values published by upstream systems)	MAXIMUM Number of SIGNIFICANT DIGITS to the right of the decimal (values received by CRS)	MAXIMUM Number of SIGNIFICANT DIGITS to the right of the decimal (externally passed from CRS in settlement statements or data files)	Comments
$DA_DQSI_{k,h}^{i,t}$	*Schedule of record* dispatch quantity scheduled for injection at an *intertie metering point*	1	1	1	• Not published via upstream *IESO* systems. • Passed to *market participants* via dispatch messaging.
$DA_DQSI_{k,h}^{m,t}$	*Schedule of record* dispatch quantity scheduled for injection at a *delivery point*	1	1	1	• Not published via upstream *IESO* systems. • Passed to *market participants* via dispatch messaging.
$DA_DQSW_{k,h}^{i,t}$	*Schedule of record* dispatch quantity scheduled for withdrawal at an *intertie metering point*	1	1	1	• Not published via upstream *IESO* systems. • Passed to *market participants* via dispatch messaging.
$DA_ELMP_{h}^{m,t}$	*Pre-dispatch* constrained schedule price for an *intertie metering point* in the export zone	2	2	2	• MIM Publication.
$DA_ILMP_{h}^{m,t}$	*Pre-dispatch* constrained schedule price for an *intertie metering point* in the import zone	2	2	2	• MIM Publication.

Variable referenced in Section 2.1	Data Description	Number of DECIMAL PLACES (values published by upstream systems)	MAXIMUM Number of SIGNIFICANT DIGITS to the right of the decimal (values received by CRS)	MAXIMUM Number of SIGNIFICANT DIGITS to the right of the decimal (externally passed from CRS in settlement statements or data files)	Comments
$DA_SNLC_{k,h}^{m}$	Speed-no-load costs submitted into the *schedule of record*	1	2	1	• Not published via upstream *IESO* systems. • Passed to *market participants* via dispatch messaging.
$DA_SNLC_{k,h}^{p}$	Speed-no-load costs for pseudo units submitted into the *schedule of record*	1	2	1	• Not published via upstream *IESO* systems. • Passed to *market participants* via dispatch messaging.
$DA_SUC_{k,h}^{m}$	Start-up costs submitted into the *schedule of record*	1	2	1	• Not published via upstream *IESO* systems. • Passed to *market participants* via dispatch messaging.
$DA_SUC_{k,h}^{p}$	Start-up costs for pseudo units submitted into the *schedule of record*	1	2	1	• Not published via upstream *IESO* systems. • Passed to *market participants* via dispatch messaging.
$DIPC_{k,h}^{m,t}$	Derived Interval Price Curve	1	2	1	• Derived price curve and therefore not published on *settlement statements.*
$DIGQ_{k,h}^{m,t}$	Derived Interval Guaranteed Quantity	1	1	1	• Derived schedule quantity and therefore not published on *settlement statements.*

Variable referenced in Section 2.1	Data Description	Number of DECIMAL PLACES (values published by upstream systems)	MAXIMUM Number of SIGNIFICANT DIGITS to the right of the decimal (values received by CRS)	MAXIMUM Number of SIGNIFICANT DIGITS to the right of the decimal (externally passed from CRS in settlement statements or data files)	Comments
$DQSI_{k,h}^{m,t}$	Dispatch Quantity of Energy Scheduled for Injection	1	1	1	• Not published via upstream *IESO* systems. • Passed to *market participants* via dispatch messaging.
$DQSR_{r,k,h}^{m,t}$	Dispatch Quantity Schedule of Operating Reserve	1	1	1	• Not published via upstream *IESO* systems. • Passed to *market participants* via dispatch messaging.
$DQSW_{k,h}^{m,t}$	Dispatch Quantity of Energy Scheduled for Withdrawal	1	1	1	• Not published via upstream *IESO* systems. • Passed to *market participants* via dispatch messaging.
DRACP	Demand Response Auction Clearing Price	2	2	2	• Published in post-auction report.
$DRACP_h$	Hourly Demand Response Auction Clearing Price	N/A	2	2	• Not published via upstream *IESO* systems.

Variable referenced in Section 2.1	Data Description	Number of DECIMAL PLACES (values published by upstream systems)	MAXIMUM Number of SIGNIFICANT DIGITS to the right of the decimal (values received by CRS)	MAXIMUM Number of SIGNIFICANT DIGITS to the right of the decimal (externally passed from CRS in settlement statements or data files)	Comments
$DRBOC_k$	Demand Response Buy-Out Capacity	N/A	3	3	• Not published via upstream *IESO* systems.
$DRCO_k$	Demand Response Capacity Obligation (MW)	1	3	3	• Published in private post-auction report.
$DREBQ^m_{k,h}$	Demand Response Energy Bid Quantity	N/A	1	1	• Not published via upstream *IESO* systems.
DRNPF	Demand Response Non-Performance Factor	N/A	1	1	• Not published via upstream *IESO* systems.
$DRSQTY^m_{k,h}$	Demand Response Scheduled Quantity	N/A	1	1	• Not published via upstream *IESO* systems.
EEQ	Excluded Energy Quantity	N/A	3	3	• Not published via upstream *IESO* systems.

Variable referenced in Section 2.1	Data Description	Number of DECIMAL PLACES (values published by upstream systems)	MAXIMUM Number of SIGNIFICANT DIGITS to the right of the decimal (values received by CRS)	MAXIMUM Number of SIGNIFICANT DIGITS to the right of the decimal (externally passed from CRS in settlement statements or data files)	Comments
$EGEI_k$	Embedded Generator Energy Injection	N/A	3	3	• Not published via upstream *IESO* systems.
$EIM_{k,h}$	Operating Profit Function for the IMPORT of Energy under the Intertie Offer/Bid Guarantee Settlement Credit	N/A See Section 2.4	N/A See Section 2.4	N/A See Section 2.4	• This acronym is associated with the energy import component of the Intertie Offer/Bid Guarantee Settlement Credit.
$EMP_h^{i,t}$	5-minute Energy Market Price at the Interties	2	2	2	• MIM Publication.
$EMP_h^{m,t}$	5-minute Energy Market Price within Ontario	2	2	2	• MIM Publication.
$EMP_h^{REF,t}$	5-minute Energy Market Reference Price	2	2	2	• MIM Publication.
ETS	Export Transmission Service Tariff Rate	N/A	2	2	• Not published via upstream *IESO* systems. • Subject to the OEB "Ontario Transmission Rate Order".
FP_h^m	Fixed Energy Rate	N/A	2	2	• Not published via upstream *IESO* systems.
FPC_h^m	Rate for a designated group of *charge types* (see description of *charge type* 141))	N/A	2	2	• Not published via upstream *IESO* systems.

Variable referenced in Section 2.1	Data Description	Number of DECIMAL PLACES (values published by upstream systems)	MAXIMUM Number of SIGNIFICANT DIGITS to the right of the decimal (values received by CRS)	MAXIMUM Number of SIGNIFICANT DIGITS to the right of the decimal (externally passed from CRS in settlement statements or data files)	Comments
GRP	Generator Regulated Price	N/A	2	2	• Not published via upstream *IESO* systems.
$HDRBP^{m}_{k,h}$	HDR bid price	N/A	1	1	• Not published via upstream *IESO* systems.
$HDRDC^{m}_{k,h}$	Measured hourly demand response capacity	N/A	3	3	• Not published via upstream *IESO* systems.
HDRTAPR	Out of market test activation payment rate	N/A	N/A	N/A	• Not published via upstream IESO systems • Fixed rate as defined in this document
$HOEP_h$	Hourly Ontario Energy Price	2	2	2	• MIM Publication.
$LCD_{k,h}^{m}$	Line Connection Demand (KW)	2 and 3	3	3	• RMS presentation is in units of KW to 2 decimal places. • Unit changes to MW to 3 decimal places prior to transfer to the Transmission Tariff Demand Calculator (TTDC). • Unit changes to KW to 3 decimal places prior to transfer to CRS.
$MAX_CAP_{k,h}^{m,t}$	Maximum Capacity	2	3	3	
MC_h^m	Minimum Consumption	1	1	1	

Variable referenced in Section 2.1	Data Description	Number of DECIMAL PLACES (values published by upstream systems)	MAXIMUM Number of SIGNIFICANT DIGITS to the right of the decimal (values received by CRS)	MAXIMUM Number of SIGNIFICANT DIGITS to the right of the decimal (externally passed from CRS in settlement statements or data files)	Comments
MI	Ordered matrix of and corresponding IOG *settlement amounts*	1 and 2	2	2	• Derived set of variables and therefore not published on *settlement statements.*
$MLP_{k,h}^{m,t}$	Minimum Loading Point	1	1	1	• Not published via upstream *IESO* systems.
$MLP_CONS_{k,h}^{m,t}$	Minimum Loading Point for a steam turbine resource or a combustion turbine resource associated to a pseudo unit	1	1	1	• Not published via upstream *IESO* systems.
$MQSI_{k,h}^{m,t}$	Market Quantity Scheduled for Injection	1	1	1	
$MQSI\{adj\}_{k,h}^{m,t}$	Adjusted Market Quantity Scheduled for Injection	1	1	1	• Derived variable and therefore not published on *settlement statements.*
$MQSW_{k,h}^{m,t}$	Market Quantity Scheduled for Withdrawal	1	1	1	
$NSD_{k,h}^{m}$	Network Service Demand (KW)	2 and 3	3	3	• RMS presentation is in units of KW to 2 decimal places. • Unit changes to MW to 3 decimal places prior to transfer to the Transmission Tariff Demand Calculator (TTDC). • Unit changes to KW to 3 decimal places prior to transfer to CRS.

Variable referenced in Section 2.1	Data Description	Number of DECIMAL PLACES (values published by upstream systems)	MAXIMUM Number of SIGNIFICANT DIGITS to the right of the decimal (values received by CRS)	MAXIMUM Number of SIGNIFICANT DIGITS to the right of the decimal (externally passed from CRS in settlement statements or data files)	Comments
$OCMW^{i}_{k}$	Over committed MWs	1	1	1	• Not published via upstream *IESO* systems.
OP	Operating Profit Function	N/A See Section 2.4	N/A See Section 2.4	N/A See Section 2.4	• This acronym is associated with the operating profit equation used within the CMSC equation.
$OPCAP_{k,h}^{m,t}$	Operating Capacity	1	1	1	• Not published via upstream *IESO* systems.
$PB_IM_{h}^{t}$	Price bias adjustment factor for import transactions	2	2	2	• Published on by the *IESO* on a periodic basis.
$PB_EX_{h}^{t}$	Price bias adjustment factor for export transactions	2	2	2	• Published on by the *IESO* on a periodic basis.
$PD_BE_{k,h}^{i,t}$	*Energy Offer* submitted into the *Pre-dispatch*	N/A	1	1	• Not published via upstream *IESO* systems. • Confirmations passed to *market participants* as *bids*/*offers* (“*dispatch data*”) are received.
$PD_BL_{k,h}^{i,t}$	*Energy bids* submitted into the *Pre-dispatch*	N/A	1	1	• Not published via upstream *IESO* systems. • Confirmations passed to *market participants* as *bids*/*offers* (“*dispatch data*”) are received.

Variable referenced in Section 2.1	Data Description	Number of DECIMAL PLACES (values published by upstream systems)	MAXIMUM Number of SIGNIFICANT DIGITS to the right of the decimal (values received by CRS)	MAXIMUM Number of SIGNIFICANT DIGITS to the right of the decimal (externally passed from CRS in settlement statements or data files)	Comments
$PD_DQSI_{k,h}^{i,t}$	*Pre-dispatch* quantity scheduled for injection at an *intertie metering point*	1	1	1	• Not published via upstream *IESO* systems. • Passed to *market participants* via dispatch messaging.
$PD_DQSW_{k,h}^{i,t}$	*Pre-dispatch* quantity scheduled for withdrawal at an *intertie metering point*	1	1	1	• Not published via upstream *IESO* systems. • Passed to *market participants* via dispatch messaging.
$PD_ELMP_{h}^{m,t}$	*Pre-dispatch* constrained schedule price for an *intertie metering point* in the export zone	2	2	2	• MIM Publication.
$PD_EMP_{h}^{m,t}$	Pre-dispatch energy market price for Ontario	2	2	2	• MIM Publication.
$PD_ILMP_{h}^{m,t}$	*Pre-dispatch* constrained schedule price for an *intertie metering point* in the import zone	2	2	2	• MIM Publication.
$PROR_{r,h}^{m,t}$	5-minute Operating Reserve Price	2	2	5	• MIM Publication.
$PST_{k,h}^{p,t}$	Steam Turbine Portion from Daily Generator Data	1	1	1	• Not published via upstream *IESO* systems.

Variable referenced in Section 2.1	Data Description	Number of DECIMAL PLACES (values published by upstream systems)	MAXIMUM Number of SIGNIFICANT DIGITS to the right of the decimal (values received by CRS)	MAXIMUM Number of SIGNIFICANT DIGITS to the right of the decimal (externally passed from CRS in settlement statements or data files)	Comments
PTS-L	Provincial Transmission Service Line Connection Service Rate ($/KW)	N/A	2	2	• Not published via upstream *IESO* systems. • Subject to the OEB "Ontario Transmission Rate Order".
PTS-N	Provincial Transmission Service Network Service Rate ($/KW)	N/A	2	2	• Not published via upstream *IESO* systems. • Subject to the OEB "Ontario Transmission Rate Order".
PTS-T	Provincial Transmission Service Transformation Connection Service Rate ($/KW)	N/A	2	2	• Not published via upstream *IESO* systems. • Subject to the OEB "Ontario Transmission Rate Order".
$QTR_{k,h}^{i,j}$	Quantity of Transmission Rights Owned	PENDING	0	0	• TR's are in denominations to the nearest MW. • Upstream publication accuracy currently being resolved.
$RAC^{m}{}_{k}$	Resource Available Capacity	N/A	3	3	• Not published via upstream *IESO* systems.
$SQEI_{k,h}^{i,t}$	Scheduled Quantity of Energy Injected at an *intertie metering point*	1	1	1	

Variable referenced in Section 2.1	Data Description	Number of DECIMAL PLACES (values published by upstream systems)	MAXIMUM Number of SIGNIFICANT DIGITS to the right of the decimal (values received by CRS)	MAXIMUM Number of SIGNIFICANT DIGITS to the right of the decimal (externally passed from CRS in settlement statements or data files)	Comments
$SQEW_{k,h}^{i,t}$	Scheduled Quantity of Energy Withdrawn at an *intertie metering point*	1	1	1	
$SQROR_{r,k,h}^{m,t}$	Scheduled Quantity of class r *Operating Reserve*	1	1	1	
$TAOR_{k,h}^{m,t}$	Total Accessible Operating Reserve	2	3	3	
$TCD_{k,h}^{m}$	Transformation Connection Demand (KW)	2 and 3	3	3	• RMS presentation is in units of KW to 2 decimal places. • Unit changes to MW to 3 decimal places prior to transfer to the Transmission Tariff Demand Calculator (TTDC). • Unit changes to KW to 3 decimal places prior to transfer to CRS.
$TD_{k,h,c}$	Total Market Settlement Amount	N/A	N/A	N/A	• N/A- notational description of an aggregated financial amount (reported to the nearest cent when applicable).
TP_c	Tariff price	N/A	N/A	N/A	• N/A – notational description of tariff rate (reported to the nearest cent when applicable).
TRMP	TR Market Clearing Price	2	2	2	

Variable referenced in Section 2.1	Data Description	Number of DECIMAL PLACES (values published by upstream systems)	MAXIMUM Number of SIGNIFICANT DIGITS to the right of the decimal (values received by CRS)	MAXIMUM Number of SIGNIFICANT DIGITS to the right of the decimal (externally passed from CRS in settlement statements or data files)	Comments
TRCAD	TR Clearing Account Disbursements	N/A	2	2	• Not published via upstream *IESO* systems.
$TRCAD_E$	TR Clearing Account Disbursements for Exporters	N/A	2	2	• Not published via upstream *IESO* systems.
$TRCAD_L$	TR Clearing Account Disbursements for Loads	N/A	2	2	• Not published via upstream *IESO* systems.
TRCAR	TR Shortfall Recovery Amount	N/A	2	2	• Not published via upstream *IESO* systems.

2.4 Rounding Conventions – by Charge Type

2.4.1 General Notes

- **The table below references significant digits to the right of the decimal place. This should NOT be confused with the number of decimal places allowable in some columns on the *settlement statements* and data files as set out in, "Format Specification for Settlement Statements and Data Files."**

- All **settlement amounts** reported by the *IESO* settlements system are rounded to the nearest cent (i.e. to two decimal places) on *settlement statements,* although some settlement calculations may only yield 1 significant digit to the right of the decimal place. In these instances, the financial amount is NOT further rounded to the nearest ten cents. **The table below does not include the final rounding step to the nearest cent, as this is done for ALL *settlement amounts*. Rather, it describes any intermediate calculations (particularly, those involving division) that involve rounding prior to the final calculation of the *settlement amount*.**

2.4.2 Key to the Table of Rounding Conventions

Column Name	Description
Charge Type Number	This table contains an entry for each *charge type* listed in Section 2.2 of this document ("IESO Charge Types and Equations").
Charge Type Name	The name of each of the *charge types*.
INPUT VARIABLES **Least number of significant digits to the right of the decimal**	In terms of assessing the accuracy of the final *settlement amount*, this column is derived from the settlement variable received by the *settlement* system with the LEAST number of significant digits to the right of the decimal place.
INPUT VARIABLES **Maximum number of significant digits to the right of the decimal**	In terms of assessing the accuracy of the final *settlement amount*, this column is derived from the settlement variable received by the *settlement* system with the MAXIMUM number of significant digits to the right of the decimal place.
INTERMEDIATE Rounding done by Settlements	This column indicates whether or not any **INTERMEDIATE** rounding is done by the *IESO settlement process*. **This does NOT include the final rounding of *settlement amounts* to 2 decimal places as the last step in the calculation of ALL *charge types*.**

Column Name	Description
INTERMEDIATE CALCULATION 1 (where intermediate rounding occurs)	This column ONLY describes an intermediate calculation of the *settlement amount* in which rounding occurs PRIOR to the final rounding of the *settlement amount* to the nearest cent.
Disposition of INTERMEDIATE CALCULATION 1	This column describes the disposition of the rounded value resulting from Intermediate Calculation 1.
INTERMEDIATE CALCULATION 2 (where intermediate rounding occurs)	This column ONLY describes an intermediate calculation of the *settlement amount* in which rounding occurs PRIOR to the final rounding of the *settlement amount* to the nearest cent.
Disposition of INTERMEDIATE CALCULATION 2	This column describes the disposition of the rounded value resulting from Intermediate Calculation 2.

Charge Type Number	Charge Type Name	INPUT VARIABLES Least number of significant digits to the right of the decimal	INPUT VARIABLES Maximum number of significant digits to the right of the decimal	Intermediate Rounding done by Settlements?	INTERMEDIATE CALCULATION 1 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 1	INTERMEDIATE CALCULATION 2 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 2
52	Transmission Rights Auction Settlement Debit	0	2	No				
100	Net Energy Market Settlement for Generators and Dispatchable Load	1	3	Yes	Numerator: BCQ Denominator: 12 Resulting Decimals: 3	BCQ quantities Multiplied by EMP when applicable.		
101	Net Energy Market Settlement for Non-dispatchable Load	1	3	Yes	Numerator: BCQ Denominator: 12 Resulting Decimals: 3	BCQ quantities Multiplied by EMP when applicable.		
102	TR Clearing Account Credit	1	3	No				

Charge Type Number	Charge Type Name	INPUT VARIABLES Least number of significant digits to the right of the decimal	INPUT VARIABLES Maximum number of significant digits to the right of the decimal	Intermediate Rounding done by Settlements?	INTERMEDIATE CALCULATION 1 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 1	INTERMEDIATE CALCULATION 2 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 2
103	Transmission Charge Reduction Fund	2	3	Yes	Numerator: Difference between SQEW – SQEI by *intertie zone* Denominator: 12 Resulting Decimals: 3	Resulting value included with the TCRF calculation at that particular zone for the *metering interval* in question.		
104	Transmission Rights Settlement Credit	0	2	Yes	Numerator: Summation of the zonal price difference ($EMP_h^{j,t} - EMP_h^{i,t}$) Denominator: 12 Resulting Decimals: 5	Multiplied by QTR for the *settlement hour.*		
105	Congestion Management Settlement Credit for Energy	1	3	Yes	AQEI multiplied by 12 or AQEW multiplied by 12 Resulting Decimals: 3	Used in the calculation of OP(EMP, AQEI, BE) or OP(EMP, AQEW, BL) as the case may be.	Numerators OP(EMP, MQSI, BE) OP(EMP, DQSI, BE) OP(EMP, AQEI, BE) OP(EMP, MQSW, BL) OP(EMP, DQSW, BL) OP(EMP, AQEW, BL) Denominator: 12 Resulting Decimals: 2	Profits compared as applicable.
106	Congestion Management Settlement Credit for 10 Minute Spinning Reserve	1	2	Yes	Numerators OP(PROR, MQSR, BR) OP(PROR, DQSR, BR) OP(PROR, AQOR, BR) Denominator: 12 Resulting Decimals: 2	Profits compared as applicable.		

Charge Type Number	Charge Type Name	INPUT VARIABLES Least number of significant digits to the right of the decimal	INPUT VARIABLES Maximum number of significant digits to the right of the decimal	Intermediate Rounding done by Settlements?	INTERMEDIATE CALCULATION 1 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 1	INTERMEDIATE CALCULATION 2 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 2
107	Congestion Management Settlement Credit for 10 Minute Non-spinning Reserve	1	2	Yes	Numerators OP(PROR, MQSR, BR) OP(PROR, DQSR, BR) OP(PROR, AQOR, BR) Denominator: 12 Resulting Decimals: 2	Profits compared as applicable.		
108	Congestion Management Settlement Credit for 30 Minute Operating Reserve	1	2	Yes	Numerators OP(PROR, MQSR, BR) OP(PROR, DQSR, BR) OP(PROR, AQOR, BR) Denominator: 12 Resulting Decimals: 2	Profits compared as applicable.		
111	Northern Pulp and Paper Mill Electricity Transition Program Settlement Amount	1	3	No				
112	Ontario Power Generation Rebate	2	3	No				
113	Additional Compensation for Administrative Pricing Credit	1	3	Yes	For the calculation outlined in 7.8.4A.16 only: for dispatchable *facilities* located within Ontario only AQEI multiplied by 12 or AQEW multiplied by 12 Resulting Decimals: 3	(For the calculation outlined in 7.8.4A.16 only) For dispatchable *facilities* located within Ontario only: Used in the calculation of OP(EMP, AQEI, BE) or OP(EMP, AQEW, BL) as the case may be.	For the calculation outlined in 7.8.4A.16 only: Numerators: for dispatchable *facilities* located within Ontario: OP(EMP, AQEI, BE) OP(EMP, AQEW, BL) for Imports or Exports:	(For the calculation outlined in 7.8.4A.16 only) The results are used in the final calculation

Charge Type Number	Charge Type Name	INPUT VARIABLES Least number of significant digits to the right of the decimal	INPUT VARIABLES Maximum number of significant digits to the right of the decimal	Intermediate Rounding done by Settlements?	INTERMEDIATE CALCULATION 1 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 1	INTERMEDIATE CALCULATION 2 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 2
							OP(EMP, DQSI, BE) OP(EMP, DQSW, BL) Denominator: 12 Resulting Decimals: 2	
114	Outage Cancellation/ Deferral Settlement Credit	2	2	No				
115	Unrecoverable Testing Costs Credit	2	2	No				
116	Tieline Maintenance Reliability Credit	2	2	No				
118	Emergency Energy Rebate	1	3	No				
119	Station Service Reimbursement Credit	2	2	No				
120	Local Market Power Debit	2	2	No				
121	Northern Energy Advantage Program Settlement Amount	1	3	No				
122	Ramp Down Settlement Amount	1	3	Yes	AQEI multiplied by 12 or AQEW multiplied by 12	Used in the calculation of OP(EMP, AQEI, BE) or OP(EMP, AQEW, BL) as the case may be.	Numerators OP(EMP, MQSI, BE) OP(EMP, DQSI, BE)	Profits compared as applicable.

Charge Type Number	Charge Type Name	INPUT VARIABLES Least number of significant digits to the right of the decimal	INPUT VARIABLES Maximum number of significant digits to the right of the decimal	Intermediate Rounding done by Settlements?	INTERMEDIATE CALCULATION 1 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 1	INTERMEDIATE CALCULATION 2 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 2
					Resulting Decimals: 3		OP(EMP, AQEI, BE) OP(EMP, MQSW, BL) OP(EMP, DQSW, BL) OP(EMP, AQEW, BL) Denominator: 12 Resulting Decimals: 2	
123	MACD Enforcement Activity Amount	2	2	No				
124	SEAL Congestion Management Settlement Credit Amount	2	2	No				
130	Intertie Offer Settlement Credit – Energy	1	3	Yes	Numerators OP(EMP, MQSI, BE) Denominator: 12 Resulting Decimals: 2	Profits compared as applicable.		
133	Generator Cost Guarantee Payment	1	3	No				
134	Demand Response Credit	2	2	No				
135	Real-time Import Failure Charge	1	3	Yes	**TERM 1 – Failure Charge** Numerator: EMP + PB_IM – PD_EMP Denominator: 12	TERM 1 and TERM 2 compared as applicable.		

Charge Type Number	Charge Type Name	INPUT VARIABLES Least number of significant digits to the right of the decimal	INPUT VARIABLES Maximum number of significant digits to the right of the decimal	Intermediate Rounding done by Settlements?	INTERMEDIATE CALCULATION 1 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 1	INTERMEDIATE CALCULATION 2 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 2
					Resulting Decimals: 2 **TERM 2 – Price Cap** Numerator: MAX(0,EMP) * RT_ISD Denominator: 12 Resulting Decimals: 2			
136	Real-time Export Failure Charge	1	3	Yes	**TERM 1 – Failure Charge** Numerator: PD_EMP – EMP – PB_EX Denominator: 12 Resulting Decimals: 2 **TERM 2 – Price Cap** Numerator: MAX(0,PD_EMP) * RT_ESD Denominator: 12 Resulting Decimals: 2	TERM 1 and TERM 2 compared as applicable.		
137	Generation Cost Guarantee – Annual Carbon Charge Settlement Amount	1	3	No				
140	Fixed Energy Rate Settlement Amount	1	3	No				
141	Fixed Wholesale Charge Rate Settlement Amount	1	3	No				

Charge Type Number	Charge Type Name	INPUT VARIABLES Least number of significant digits to the right of the decimal	INPUT VARIABLES Maximum number of significant digits to the right of the decimal	Intermediate Rounding done by Settlements?	INTERMEDIATE CALCULATION 1 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 1	INTERMEDIATE CALCULATION 2 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 2
142	Regulated Price Plan Settlement Amount	1	3	No				
143	NUG Contract Adjustment Settlement Amount	1	3	No				
144	Regulated Nuclear Generation Adjustment Amount	1	3	No				
145	Regulated Hydroelectric Generation Adjustment Amount	1	3	No				
146	Global Adjustment Settlement Amount	1	3	No				
147	Class A – Global Adjustment Settlement Amount	1	3	No				
148	Class B – Global Adjustment Settlement Amount	1	3	No				
149	Regulated Price Plan Retailer Settlement Amount	1	3	No				
150	Net Energy Market Settlement Uplift	1	3	No				

Charge Type Number	Charge Type Name	INPUT VARIABLES Least number of significant digits to the right of the decimal	INPUT VARIABLES Maximum number of significant digits to the right of the decimal	Intermediate Rounding done by Settlements?	INTERMEDIATE CALCULATION 1 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 1	INTERMEDIATE CALCULATION 2 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 2
155	Congestion Management Settlement Uplift	1	3	No				
161`	Northern Pulp and Paper Mill Electricity Transition Program Balancing Amount	1	3	No				
162	Ontario Power Generation Rebate Debit	1	3	No				
163	Additional Compensation for Administrative Pricing Debit	1	3	No				
164	Outage Cancellation/ Deferral Debit	1	3	No				
165	Unrecoverable Testing Costs Debit	1	3	No				
166	Tieline Reliability Maintenance Debit	1	3	No				
167	Emergency Energy and EDRP Debit	1	3	No				
168	TR Market Shortfall Debit	1	3	No				

Charge Type Number	Charge Type Name	INPUT VARIABLES Least number of significant digits to the right of the decimal	INPUT VARIABLES Maximum number of significant digits to the right of the decimal	Intermediate Rounding done by Settlements?	INTERMEDIATE CALCULATION 1 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 1	INTERMEDIATE CALCULATION 2 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 2
169	Station Service Reimbursement Debit	1	3	No				
170	Local Market Power Rebate	1	3	No				
171	Northern Energy Advantage Program Balancing Amount	1	3	No				
173	MACD Enforcement Activity Balancing Amount	2	2	No				
183	Generator Cost Guarantee Recovery Debit	1	3	No				
184	Demand Response Debit	2	2	No				
186	Intertie Failure Charge Rebate	1	3	No				
190	Fixed Energy Rate Balancing Amount	2	2	No				
191	Fixed Wholesale Charge Rate Balancing Amount	2	2	No				
192	Regulated Price Plan Balancing Amount	2	2	No				

Charge Type Number	Charge Type Name	INPUT VARIABLES Least number of significant digits to the right of the decimal	INPUT VARIABLES Maximum number of significant digits to the right of the decimal	Intermediate Rounding done by Settlements?	INTERMEDIATE CALCULATION 1 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 1	INTERMEDIATE CALCULATION 2 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 2
193	NUG Contract Adjustment Balancing Amount	2	2	No				
194	Regulated Nuclear Generation Balancing Amount	2	2	No				
195	Regulated Hydroelectric Generation Balancing Amount	2	2	No				
196	Global Adjustment Balancing Amount	2	2	No				
197	Global Adjustment-Special Programs Balancing Amount	2	2	No				
198	Renewable Generation Balancing Amount	2	2	No				
199	Regulated Price Plan Retailer Balancing Amount	2	2	No				
200	10 Minute Spinning Reserve Market Settlement Credit.	1	2	No				
201	10 Minute Spinning Reserve Market Shortfall Rebate	1	3	No				
202	10 Minute Non-spinning Reserve	1	2	No				

Charge Type Number	Charge Type Name	INPUT VARIABLES Least number of significant digits to the right of the decimal	INPUT VARIABLES Maximum number of significant digits to the right of the decimal	Intermediate Rounding done by Settlements?	INTERMEDIATE CALCULATION 1 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 1	INTERMEDIATE CALCULATION 2 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 2
	Market Settlement Credit							
203	10 Minute Non-spinning Reserve Market Shortfall Rebate	1	3	No				
204	30 Minute Operating Reserve Market Settlement Credit	1	2	No				
205	30 Minute Operating Reserve Market Shortfall Rebate	1	3	No				
206	10-Minute spinning non-Accessibility Settlement Amount	1	3	No				
208	10-Minute non-Spinning non-Accessibility Settlement Amount	1	3	No				
210	30-Minute non-Accessibility Settlement Amount	1	3	No				
250	10 Minute Spinning Market Reserve Hourly Uplift	1	3	No				
251	10 Minute Spinning Market Reserve Shortfall Debit	1	3	No				

Charge Type Number	Charge Type Name	INPUT VARIABLES Least number of significant digits to the right of the decimal	INPUT VARIABLES Maximum number of significant digits to the right of the decimal	Intermediate Rounding done by Settlements?	INTERMEDIATE CALCULATION 1 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 1	INTERMEDIATE CALCULATION 2 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 2
252	10 Minute Non-spinning Market Reserve Hourly Uplift	1	3	No				
253	10 Minute Non-spinning Market Reserve Shortfall Debit	1	3	No				
254	30 Minute Operating Reserve Market Hourly Uplift	1	3	No				
255	30 Minute Operating Reserve Market Shortfall Debit	1	3	No				
400	Black Start Capability Settlement Credit	2	2	No				
404	Regulation Service Settlement Credit	2	2	No				
406	Emergency Demand Response Credit	2	2	No				
410	IESO-Controlled Grid Special Operations Credit	2	2	No				
450	Black Start Capability Settlement Debit	1	3	No				

Charge Type Number	Charge Type Name	INPUT VARIABLES Least number of significant digits to the right of the decimal	INPUT VARIABLES Maximum number of significant digits to the right of the decimal	Intermediate Rounding done by Settlements?	INTERMEDIATE CALCULATION 1 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 1	INTERMEDIATE CALCULATION 2 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 2
451	Hourly Reactive Support and Voltage Control Settlement Debit	1	3	No				
452	Monthly Reactive Support and Voltage Control Settlement Debit	1	3	No				
454	Regulation Service Settlement Debit	1	3	No				
460	IESO-Controlled Grid Special Operations Debit	2	2	No				
500	Must Run Contract Settlement Credit	2	2	No				
550	Must Run Contract Settlement Debit	1	3	No				
600	Network Service Credit	2	3	No				
601	Line Connection Service Credit	2	3	No				
602	Transformation Connection Service Credit	2	3	No				
603	Export Transmission Service Credit	1	2	No				

Charge Type Number	Charge Type Name	INPUT VARIABLES Least number of significant digits to the right of the decimal	INPUT VARIABLES Maximum number of significant digits to the right of the decimal	Intermediate Rounding done by Settlements?	INTERMEDIATE CALCULATION 1 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 1	INTERMEDIATE CALCULATION 2 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 2
650	Network Service Charge	2	3	No				
651	Line Connection Service Charge	2	3	No				
652	Transformation Connection Service Charge	2	3	No				
653	Export Transmission Service Charge	1	2	No				
700	Dispute Resolution Settlement Credit	2	2	No				
702	Debt Retirement Credit	2	2	No				
703	Rural and Remote Settlement Credit	2	2	No				
704	OPA Administration Credit	2	2	No				
705	Ontario Fair Hydro Plan First Nations On-reserve Delivery Amount	2	2	**No**				
706	Ontario Fair Hydro Plan Distribution Rate Protection Amount	**2**	**2**	**No**				

Charge Type Number	Charge Type Name	INPUT VARIABLES Least number of significant digits to the right of the decimal	INPUT VARIABLES Maximum number of significant digits to the right of the decimal	Intermediate Rounding done by Settlements?	INTERMEDIATE CALCULATION 1 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 1	INTERMEDIATE CALCULATION 2 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 2
750	Dispute Resolution Settlement Debit	2	2	No				
751	Dispute Resolution Board Service Debit	2	2	No				
752	Debt Retirement Charge	2	3	No				
753	Rural and Remote Settlement Debit	2	3	No				
754	OPA Administration Charge	1	3	No				
755	MOE - Ontario Fair Hydro Plan First Nations On-reserve Delivery Balancing Amount	**2**	**2**	**No**				
756	MOE - Ontario Fair Hydro Plan Distribution Rate Protection Balancing Amount	**2**	**2**	**No**				
850	Market Participant Default Settlement Debit (recovery)	2	2	No				
851	Market Participant Default Interest Debit	2	2	No				
900	GST/HST Credit	2	2	No				
950	GST/HST Debit	2	2	No				

Charge Type Number	Charge Type Name	INPUT VARIABLES Least number of significant digits to the right of the decimal	INPUT VARIABLES Maximum number of significant digits to the right of the decimal	Intermediate Rounding done by Settlements?	INTERMEDIATE CALCULATION 1 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 1	INTERMEDIATE CALCULATION 2 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 2
1050	Self-Induced Dispatchable Load CMSC Clawback	1	3	Yes	AQEW multiplied by 12 Resulting Decimals: 3	Used in the calculation of OP(EMP, AQEW, BL) as the case may be.	Numerators OP(EMP, MQSW, BL) OP(EMP, DQSW, BL) OP(EMP, AQEW, BL) OP(EMP, MC, BL) Denominator: 12 Resulting Decimals: 2	Profits compared as applicable.
1051	Ramp-Down CMSC Claw Back	2	2	No				
1101	Real-Time Energy Settlement Amount for Dispatchable Generators	1	3	Yes	Numerator: BCQ Denominator: 12 Resulting Decimals: 3	BCQ quantities Multiplied by EMP when applicable.		
1103	Real-Time Energy Settlement Amount for Dispatchable Loads	1	3	Yes	Numerator: BCQ Denominator: 12 Resulting Decimals: 3	BCQ quantities Multiplied by EMP when applicable.		
1111	Real-Time Energy Settlement Amount for Imports	1	3	Yes	Numerator: BCQ Denominator: 12 Resulting Decimals: 3	BCQ quantities Multiplied by EMP when applicable.		
1113	Real-Time Energy Settlement Amount for Exports	1	3	Yes	Numerator: BCQ Denominator: 12 Resulting Decimals: 3	BCQ quantities Multiplied by EMP when applicable.		
1114	Real-Time Energy Settlement Amount for Non-Dispatchable Generators	1	3	Yes	Numerator: BCQ Denominator: 12 Resulting Decimals: 3	BCQ quantities Multiplied by EMP when applicable.		

Charge Type Number	Charge Type Name	INPUT VARIABLES Least number of significant digits to the right of the decimal	INPUT VARIABLES Maximum number of significant digits to the right of the decimal	Intermediate Rounding done by Settlements?	INTERMEDIATE CALCULATION 1 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 1	INTERMEDIATE CALCULATION 2 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 2
1115	Real-Time Energy Settlement Amount for Non-Dispatchable Load	1	3	Yes	Numerator: BCQ Denominator: 12 Resulting Decimals: 3	BCQ quantities Multiplied by EMP when applicable.		
1130	Day-Ahead Intertie Offer Guarantee Settlement Credit	1	3	Yes	**FOR EACH 5-MINUTE *METERING INTERVAL:*** Numerators OP[EMP, MIN(DQSI, PDR_DQSI), PDR_BE] Denominator: 12 Resulting Decimals: 2	Results for each 5-minute *metering interval* are summed for the hour. Profits compared as applicable.		
1131	Intertie Offer Guarantee Settlement Credit	1	3	Yes	**For each 5 minute metering interval:** **RT-IOG – Real Time IOG** Numerator OP(EMP,MQSI,BE) Denominator: 12 Resulting Decimal: 2 **DA-IOG - Day-Ahead IOG** **Component 1** Numerator OP(EMP, Min(DA_DQSI,DQSI),DA_BE)	**For DA-IOG**, Component 1, Component 2 and Component 3 are compared as applicable. Results of RT-IOG and DA-IOG are compared in IOG OFFSET component.		

Charge Type Number	Charge Type Name	INPUT VARIABLES Least number of significant digits to the right of the decimal	INPUT VARIABLES Maximum number of significant digits to the right of the decimal	Intermediate Rounding done by Settlements?	INTERMEDIATE CALCULATION 1 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 1	INTERMEDIATE CALCULATION 2 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 2
					Denominator: 12 Resulting Decimal: 2 **Component 2** Numerator XDA_BE – MAX(0,XBE) Denominator: 12 Resulting Decimal: 2 **Component 3** Numerator OP(EMP,MQSI,BE), OP(EMP,DA_DQSI,BE) OP(EMP,DQSI,BE) Denominator: 12 Resulting Decimal: 2 **IOG Rate** Resulting Decimal: 5			
1133	Day-Ahead Generation Cost Guarantee Payment	1	3	No				

Charge Type Number	Charge Type Name	INPUT VARIABLES Least number of significant digits to the right of the decimal	INPUT VARIABLES Maximum number of significant digits to the right of the decimal	Intermediate Rounding done by Settlements?	INTERMEDIATE CALCULATION 1 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 1	INTERMEDIATE CALCULATION 2 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 2
1134	Day-Ahead Linked Wheel Failure Charge	1	3	Yes	**RT_EFC_DALW and RT_IFC_DALW for each 5-minute metering interval are summed for the hour.** **Resulting Decimal: 2**	**Results are compared as applicable.**		
1135	Day-Ahead Import Failure Charge	1	3	Yes	**TERM 1 – Operating Profit („OP") Function used to calculate Failure Charge** OP(PD_EMP, DA_DQSI, DA_BE) OP(PD_EMP, PD_DQSI, DA_BE) Resulting Decimals: 2 **TERM 2 – Operating Profit („OP") Function used to calculate Failure Charge** OP(PD_EMP, DA_DQSI, PD_BE) OP(PD_EMP, PD_DQSI, PD_BE) Resulting Decimals: 2	TERM 1, TERM 2 and TERM 3 compared as applicable.		

Charge Type Number	Charge Type Name	INPUT VARIABLES Least number of significant digits to the right of the decimal	INPUT VARIABLES Maximum number of significant digits to the right of the decimal	Intermediate Rounding done by Settlements?	INTERMEDIATE CALCULATION 1 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 1	INTERMEDIATE CALCULATION 2 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 2
					TERM 3 – Price cap Numerator Max(0,PD_EMP) × DA_ISD Denominator: 12 Resulting Decimals: 2			
1136	Day-Ahead Export Failure Charge	1	3	Yes	**TERM 1 – Operating Profit („OP") Function used to calculate Failure Charge** OP(PD_EMP, DA_DQSW, DA_BL) OP(PD_EMP, PD_DQSW, DA_BL) Resulting Decimals: 2 **TERM 2 – Operating Profit („OP") Function used to calculate Failure Charge** OP(PD_EMP, DA_DQSW, PD_BL) OP(PD_EMP, PD_DQSW, PD_BL)	TERM 1, TERM 2 and TERM 3 compared as applicable.		

Charge Type Number	Charge Type Name	INPUT VARIABLES Least number of significant digits to the right of the decimal	INPUT VARIABLES Maximum number of significant digits to the right of the decimal	Intermediate Rounding done by Settlements?	INTERMEDIATE CALCULATION 1 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 1	INTERMEDIATE CALCULATION 2 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 2
					Resulting Decimals: 2			
1137	Intertie Offer Guarantee Reversal	2	2	No				
1138	Day-Ahead Fuel Cost Compensation Credit	2	2	No				
1139	Intertie Failure Charge Reversal	2	2	No				
1142	Ontario Fair Hydro Plan Eligible RPP Consumer Discount Settlement Amount	**2**	**2**	**No**				
1143	Ontario Fair Hydro Plan Eligible Non-RPP Consumer Discount Settlement Amount	**2**	**2**	**No**				
1144	Ontario Fair Hydro Plan Financing Entity Amount	**2**	**2**	**No**				
1145	Ontario Fair Hydro Plan Financing Entity Interest	**2**	**2**	**No**				
1148	GA Energy Storage Injection Reimbursement	2	2	No				
1188	Day-Ahead Fuel Cost Compensation Debit	1	3	No				

Charge Type Number	Charge Type Name	INPUT VARIABLES Least number of significant digits to the right of the decimal	INPUT VARIABLES Maximum number of significant digits to the right of the decimal	Intermediate Rounding done by Settlements?	INTERMEDIATE CALCULATION 1 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 1	INTERMEDIATE CALCULATION 2 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 2
1192	Ontario Fair Hydro Plan Eligible RPP Consumer Discount Balancing Amount	**2**	**2**	**No**				
1193	Ontario Fair Hydro Plan Eligible Non-RPP Consumer Discount Balancing Amount	**2**	**2**	**No**				
1194	Ontario Fair Hydro Plan Financing Entity Balancing Amount	**2**	**2**	**No**				
1195	Ontario Fair Hydro Plan Financing Entity Balancing Interest	**2**	**2**	**No**				
1300	Capacity Based Demand Response Program Availability Payment Settlement Amount	1	3	No				
1301	Capacity Based Demand Response Program Availability Over-Delivery Settlement Amt	1	3	No				
1302	Capacity Based Demand Response Program	1	3	No				

Charge Type Number	Charge Type Name	INPUT VARIABLES Least number of significant digits to the right of the decimal	INPUT VARIABLES Maximum number of significant digits to the right of the decimal	Intermediate Rounding done by Settlements?	INTERMEDIATE CALCULATION 1 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 1	INTERMEDIATE CALCULATION 2 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 2
	Availability Set-Off Settlement Amount							
1303	Capacity Based Demand Response Program Utilization Payment Settlement Amount	1	3	No				
1304	Capacity Based Demand Response Program Utilization Set-Off Settlement Amount	1	3	No				
1305	Capacity Based Demand Response Program Planned Non-Performance Event Set-Off Amt	1	3	No				
1306	Capacity Based Demand Response Program Measurement Data Set-Off Settlement Amt	1	3	No				
1307	Capacity Based Demand Response Program Buy-Down Settlement Amount	1	3	No				
1308	Capacity Based Demand Response Program Performance Breach Settlement Amount	1	3	No				

Charge Type Number	Charge Type Name	INPUT VARIABLES Least number of significant digits to the right of the decimal	INPUT VARIABLES Maximum number of significant digits to the right of the decimal	Intermediate Rounding done by Settlements?	INTERMEDIATE CALCULATION 1 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 1	INTERMEDIATE CALCULATION 2 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 2
1309	Demand Response Pilot – Availability Payment	1	3	No				
1310	Demand Response Pilot – Availability Clawback	1	3	No				
1311	Demand Response Pilot – Availability Charge	1	3	No				
1312	Demand Response Pilot – Availability Adjustment	1	3	No				
1313	Demand Response Pilot – Demand Response Bid Guarantee	1	3	No				
1314	Capacity Obligation – Availability Payment	1	3	No				
1315	Capacity Obligation – Availability Charge	1	3	No				
1316	Capacity Obligation – Administration Charge	1	3	No				
1317	Capacity Obligation – Dispatch Charge	1	3	No				
1318	Capacity Obligation – Capacity Charge	1	3	No				

Charge Type Number	Charge Type Name	INPUT VARIABLES Least number of significant digits to the right of the decimal	INPUT VARIABLES Maximum number of significant digits to the right of the decimal	Intermediate Rounding done by Settlements?	INTERMEDIATE CALCULATION 1 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 1	INTERMEDIATE CALCULATION 2 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 2
1319	Capacity Obligation – Buy-Out Charge	1	3	No				
1320	Capacity Obligation – Out of Market Activation Payment	1	3	No				
1321	Capacity Obligation – Capacity Import Call Failure Charge	1	3	No				
1322	Capacity Obligation – Capacity Deficiency Charge	1	3	No				
1323	Capacity Obligation – In-Period UCAP Adjustment Charge	1	3	No				
1324	Capacity Obligation – Availability Charge True-up Payment	1	3	No				
1325	Capacity Obligation – Capacity Auction Charges True-up Payment	1	3	No				
1330	On behalf of *Former* OPA for the DR2 Program – Availability Payment Settlement Amount	1	3	No				
1331	On behalf of *Former* OPA for the DR2 Program –	1	3	No				

Charge Type Number	Charge Type Name	INPUT VARIABLES Least number of significant digits to the right of the decimal	INPUT VARIABLES Maximum number of significant digits to the right of the decimal	Intermediate Rounding done by Settlements?	INTERMEDIATE CALCULATION 1 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 1	INTERMEDIATE CALCULATION 2 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 2
	Availability Set-Off Settlement Amount							
1332	On behalf of *Former* OPA for the DR2 Program – Utilization Payment Settlement Amount	1	3	No				
1333	On behalf of *Former* OPA for the DR2 Program – Utilization Set-Off Settlement Amount	1	3	No				
1334	On behalf of *Former* OPA for the DR2 Program – Meter Data Set-Off Settlement Amount	1	3	No				
1335	On behalf of *Former* OPA for the DR2 Program – Buy-Down Settlement Amount	1	3	No				
1336	On behalf of *Former* OPA for the DR2 Program – Miscellaneous Settlement Amount	1	3	No				
1340	On behalf of *Former* OPA for the DR3 Program – Availability Payment Settlement Amount	1	3	No				

Charge Type Number	Charge Type Name	INPUT VARIABLES Least number of significant digits to the right of the decimal	INPUT VARIABLES Maximum number of significant digits to the right of the decimal	Intermediate Rounding done by Settlements?	INTERMEDIATE CALCULATION 1 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 1	INTERMEDIATE CALCULATION 2 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 2
1341	On behalf of *Former* OPA for the DR3 Program – Availability Over-Delivery Settlement Amt	1	3	No				
1342	On behalf of *Former* OPA for the DR3 Program – Availability Set-Off Settlement Amount	1	3	No				
1343	On behalf of *Former* OPA for the DR3 Program – Utilization Payment Settlement Amount	1	3	No				
1344	On behalf of *Former* OPA for the DR3 Program – Utilization Set-Off Settlement Amount	1	3	No				
1345	On behalf of *Former* OPA for the DR3 Program – Planned Non-Performance Event Set-Off Amt	1	3	No				
1346	On behalf of *Former* OPA for the DR3 Program – Meter Data Set-Off Settlement Amount	1	3	No				

Charge Type Number	Charge Type Name	INPUT VARIABLES Least number of significant digits to the right of the decimal	INPUT VARIABLES Maximum number of significant digits to the right of the decimal	Intermediate Rounding done by Settlements?	INTERMEDIATE CALCULATION 1 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 1	INTERMEDIATE CALCULATION 2 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 2
1347	On behalf of *Former* OPA for the DR3 Program – Buy-Down Settlement Amount	1	3	No				
1348	On behalf of *Former* OPA for the DR3 Program – Miscellaneous Settlement Amount	1	3	No				
1350	Capacity Based Recovery Amount for Class A Loads	1	3	No				
1351	Capacity Based Recovery Amount for Class B Loads	1	3	No				
1380	Demand Response 2 Availability Payment Balancing Amount	2	2	No				
1381	Demand Response 2 Availability Set-Off Balancing Amount	2	2	No				
1382	Demand Response 2 Utilization Payment Balancing Amount	2	2	No				
1383	Demand Response 2 Utilization Set-	2	2	No				

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	Off Balancing Amount							
1384	Demand Response 2 Meter Data Set-Off Balancing Amount	2	2	No				
1385	Demand Response 2 Buy-Down Balancing amount	2	2	No				
1386	Demand Response 2 Miscellaneous Balancing amount	2	2	No				
1390	Demand Response 3 Availability Payment Balancing Amount	2	2	No				
1391	Demand Response 3 Availability Over-Delivery Balancing Amount	2	2	No				
1392	Demand Response 3 Availability Set-Off Balancing Amount	2	2	No				
1393	Demand Response 3 Utilization Payment Balancing Amount	2	2	No				
1394	Demand Response 3 Utilization	2	2	No				

Charge Type Number	Charge Type Name	INPUT VARIABLES Least number of significant digits to the right of the decimal	INPUT VARIABLES Maximum number of significant digits to the right of the decimal	Intermediate Rounding done by Settlements?	INTERMEDIATE CALCULATION 1 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 1	INTERMEDIATE CALCULATION 2 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 2
	Set-Off Balancing Amount							
1395	Demand Response 3 Planned Non-Performance Event Set-Off Balancing Amount	2	2	No				
1396	Demand Response 3 Meter Data Set-Off Balancing Amount	2	2	No				
1397	Demand Response 3 Buy-Down Balancing Amount	2	2	No				
1398	Demand Response 3 Miscellaneous Balancing Amount	2	2	No				
1400	OPA Contract Adjustment Settlement Amount	1	2	No				
1401	Incremental Loss Settlement Credit	1	6	No				
1402	Hourly Condense System Constraints Settlement Credit	1	5	No				
1403	Speed-no-load Settlement Credit	1	2	No				
1404	Condense Unit Start-up and	1	2	No				

Charge Type Number	Charge Type Name	INPUT VARIABLES Least number of significant digits to the right of the decimal	INPUT VARIABLES Maximum number of significant digits to the right of the decimal	Intermediate Rounding done by Settlements?	INTERMEDIATE CALCULATION 1 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 1	INTERMEDIATE CALCULATION 2 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 2
	OM&A Settlement Credit							
1405	Hourly Condense Energy Costs Settlement Credit	1	2	No				
1406	Monthly Condense Energy Costs Settlement Credit	1	2	No				
1407	Condense Transmission Tariff Reimbursement Settlement Credit	2	3	No				
1408	Condense Availability Cost Settlement Credit	1	2	No				
1409	Monthly Condense System Constraints Settlement Credit	1	2	No				
1410	Renewable Energy Standard Offer Program Settlement Amount	1	3	No				
1411	Clean Energy Standard Offer Program Settlement Amount	1	3	No				
1412	Feed-In Tariff Program Settlement Amount	1	3	No				

Charge Type Number	Charge Type Name	INPUT VARIABLES Least number of significant digits to the right of the decimal	INPUT VARIABLES Maximum number of significant digits to the right of the decimal	Intermediate Rounding done by Settlements?	INTERMEDIATE CALCULATION 1 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 1	INTERMEDIATE CALCULATION 2 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 2
1413	Renewable Generation Connection – Monthly Compensation Settlement Credit	1	3	No				
1414	Hydroelectric Contract Initiative Settlement Amount	1	3	No				
1415	Conservation Assessment Recovery	1	3	No				
1416	Conservation and Demand Management - Compensation Settlement Credit	1	3	No				
1417	Daily Condense Energy Costs Settlement Credit	1	2	No				
1418	Biomass Non-Utility Generation Contracts Settlement Amount	1	3	No				
1419	Energy from Waste (EFW) Contracts Settlement Amount	1	3	No				
1420	Ontario Electricity Support Program Settlement Amount	2	2	No				

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1421	Capacity Agreement Settlement Credit	0	2	No				
1422	Capacity Agreement Penalty Settlement Amount	0	2	No				
1423	Energy Sales Agreement Settlement Credit	0	3	No				
1424	Energy Sales Agreement Penalty Settlement Amount	0	2	No				
1425	Hydroelectric Standard Offer Program Settlement Amount	2	2	No				
1427	Non-Hydro Renewables Funding Amount	2	2	No				
1450	OPA Contract Adjustment Balancing Amount	2	2	No				
1451	Incremental Loss Offset Settlement Amount	2	2	No				

Charge Type Number	Charge Type Name	INPUT VARIABLES Least number of significant digits to the right of the decimal	INPUT VARIABLES Maximum number of significant digits to the right of the decimal	Intermediate Rounding done by Settlements?	INTERMEDIATE CALCULATION 1 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 1	INTERMEDIATE CALCULATION 2 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 2
1457	Ontario Electricity Rebate Balancing Amount	2	2	No				
1460	Renewable Energy Standard Offer Program Balancing Amount	2	2	No				
1461	Clean Energy Standard Offer Program Balancing Amount	2	2	No				
1462	Feed-In Tariff Program Balancing Amount	2	2	No				
1463	Renewable Generation Connection – Monthly Compensation Settlement Debit	1	3	No				
1464	Hydroelectric Contract Initiative Balancing Amount	2	2	No				
1465	Ontario Clean Energy Benefit (-10%) Program Balancing Amount	2	2	No				
1466	Conservation and Demand Management -	2	2	No				

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	Compensation Balancing Amount							
1467	Ontario Rebate for Electricity Consumers (8% Provincial Rebate) Balancing Amount	2	2	No				
1468	Biomass Non-Utility Generation Contracts Balancing Amount	2	2	No				
1469	Energy from Waste (EFW) Contracts Balancing Amount	2	2	No				
1470	Ontario Electricity Support Program Balancing Amount	2	3	No				
1471	Capacity Agreement Balancing Amount	2	2	No				
1472	Capacity Agreement Penalty Balancing Amount	2	2	No				
1473	Energy Sales Agreement Balancing Amount	2	2	No				

Charge Type Number	Charge Type Name	INPUT VARIABLES Least number of significant digits to the right of the decimal	INPUT VARIABLES Maximum number of significant digits to the right of the decimal	Intermediate Rounding done by Settlements?	INTERMEDIATE CALCULATION 1 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 1	INTERMEDIATE CALCULATION 2 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 2
1474	Energy Sales Agreement Penalty Balancing Amount	2	2	No				
1475	Hydroelectric Standard Offer Program Balancing Amount	2	2	No				
1477	COVID-19 Energy Assistance Program (CEAP) Settlement Amount	2	2	No				
1487	Non-Hydro Renewables Funding Balancing Amount	2	2	No				
1500	Day-Ahead Production Cost Guarantee Payment – Component 1 and Component 1 Clawback	1	3	Yes	AQEI is multiplied by 12 Resulting decimal: 3	Use in the calculation of OP(EMP,AQEI, DA_BE),	**For each 5 minute metering interval:** Numerator OP(EMP,AQEI, DA_BE), OP(EMP,DQSI, DA_BE), OP(EMP,DA_DQSI, DA_BE) Denominator: 12 Resulting Decimal: 2 Numerator DA_SNLC	Profits are compared as applicable.

Charge Type Number	Charge Type Name	INPUT VARIABLES Least number of significant digits to the right of the decimal	INPUT VARIABLES Maximum number of significant digits to the right of the decimal	Intermediate Rounding done by Settlements?	INTERMEDIATE CALCULATION 1 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 1	INTERMEDIATE CALCULATION 2 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 2
							Denominator: 12 Resulting decimal: 2 Results for each 5-minute metering interval are summed for the hour.	
1501	Day-Ahead Production Cost Guarantee Payment – Component 2	1	3	Yes	AQEI is multiplied by 12 Resulting decimal: 3	Use in the calculation of OP(EMP,AQEI, DA_BE), OP(EMP,AQEI, BE)	**For each 5 minute metering interval:** Numerator OP(EMP,AQEI, DA_BE), OP(EMP,DQSI, DA_BE), OP(EMP,DA_DQSI, DA_BE) OP(EMP,OPCAP, DA_BE) OP(EMP,AQEI, BE), OP(EMP,DQSI, BE), OP(EMP,DA_DQSI, BE) OP(EMP,OPCAP, BE) Resulting Decimal: 2	Profits are compared as applicable.
1502	Day-Ahead Production Cost Guarantee Payment – Component 3 and Component 3 Clawback	1	3	Yes	AQEI is multiplied by 12 Resulting decimal: 3	Use in the calculation of OP(EMP,AQEI, BE),	**For each 5 minute metering interval:** Numerator OP(EMP,AQEI, BE),	Profits are compared as applicable.

Charge Type Number	Charge Type Name	INPUT VARIABLES Least number of significant digits to the right of the decimal	INPUT VARIABLES Maximum number of significant digits to the right of the decimal	Intermediate Rounding done by Settlements?	INTERMEDIATE CALCULATION 1 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 1	INTERMEDIATE CALCULATION 2 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 2
							OP(EMP,DQSI, BE), OP(EMP,DA_DQSI, BE) OP(EMP,MLP, BE) Results for each 5-minute metering interval are summed for the hour. Resulting Decimal: 2	
1503	Day-Ahead Production Cost Guarantee Payment – Component 4	1	3	Yes	**For each 5 minute metering interval:** Numerators OP(PROR,30R_SQROR,BR), OP(PROR,10NS_SQROR,BR), OP(PROR,10S_SQROR,BR), Denominator: 12 Resulting Decimal: 2	Profits are compared as applicable.		
1504	Day-Ahead Production Cost Guarantee Payment – Component 5	1	3	No				
1505	Day-Ahead Production Cost Guarantee Reversal	1	3	No				

Charge Type Number	Charge Type Name	INPUT VARIABLES Least number of significant digits to the right of the decimal	INPUT VARIABLES Maximum number of significant digits to the right of the decimal	Intermediate Rounding done by Settlements?	INTERMEDIATE CALCULATION 1 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 1	INTERMEDIATE CALCULATION 2 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 2
1510	Day-Ahead Generator Withdrawal Charge	1	3	Yes	**For each 5 minute metering interval:** Numerators OP(EMP,MLP,DA_BE) or OP(PD_EMP,MLP,DA_BE) Denominator: 12 Resulting Decimal: 2	Results for each 5-minute metering interval are summed for the hour.		
1550	Day-Ahead Production Cost Guarantee Recovery Debit	1	3	No				
1560	Day-Ahead Generator Withdrawal Rebate	1	3	No				
1600	Forecasting Service Settlement Amount	1	3	No				
1650	Forecasting Service Balancing Amount	1	3	No				
1750	Dispute Resolution Balancing Amount (Market)	2	2	No				
1753	MOE - Rural and Remote Settlement Debit	2	2	No				

Charge Type Number	Charge Type Name	INPUT VARIABLES Least number of significant digits to the right of the decimal	INPUT VARIABLES Maximum number of significant digits to the right of the decimal	Intermediate Rounding done by Settlements?	INTERMEDIATE CALCULATION 1 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 1	INTERMEDIATE CALCULATION 2 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 2
2148	Class B Global Adjustment Prior Period Correction Settlement Amount	2	2	No				
2470	MOE - Ontario Electricity Support Program Balancing Amount	2	2	No				
6000	Ontario Fair Hydro Plan - Regulatory Asset Transfer Amount	2	2	No				
6050	Ontario Fair Hydro Plan - Regulatory Asset Transfer Balancing Amount	2	2	No				
6147	Class A Global Adjustment Deferral Recovery Amount	1	3	No				
6148	Class B Global Adjustment Deferral Recovery Amount	1	3	No				
9147	Class A Global Adjustment Smoothing Balancing Amount	1	3	No				
9148	Class B Global Adjustment	1	3	No				

Charge Type Number	Charge Type Name	INPUT VARIABLES Least number of significant digits to the right of the decimal	INPUT VARIABLES Maximum number of significant digits to the right of the decimal	Intermediate Rounding done by Settlements?	INTERMEDIATE CALCULATION 1 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 1	INTERMEDIATE CALCULATION 2 (where intermediate rounding occurs)	DISPOSITION OF INTERMEDIATE CALCULATION 2
	Smoothing Balancing Amount							
9920	Adjustment Account Credit	1	1	No				
9980	Smart Metering Charge	2	2	No				
9982	Ontario Rebate for Electricity Consumers (8% Provincial Rebate) Settlement Amount	2	2	No				
9983	Ontario Electricity Rebate Settlement Amount	2	2	No				
9984	COVID-19 Energy Assistance Program (CEAP) Balancing Amount	2	2	No				
9990	IESO Administration Charge	2	3	No				
9992	Ontario Clean Energy Benefit (-10%) Program Settlement Amount	2	2	No				
9996	Recovery of Costs	2	2	No				

2.5 Settlement of Physical Bilateral Contracts

2.5.1 Governing Rules

Settlement of *physical bilateral contracts* is discussed in Section 2.1 of Chapter 8, of the *IESO market rules*. In summary this particular *market rules* Section prescribes the prices to be applied to a *Physical Bilateral Contract Quantity of Energy Sold* ($BCQ_{k,b,h}^{m,t}$) or a *Physical Bilateral Contract Quantity of Energy Bought* ($BCQ_{s,k,h}^{m,t}$) at a *delivery point* or an *intertie metering point.* This treatment is summarized in the table below with respect to each settlement variable defined in **Section 2.1** and *charge type* described in **Section 2.2** of this document.

Location of Bilateral Contract	Settlement of Selling Market Participant	Settlement of Buying Market Participant	Charge Type
Non-dispatchable *delivery point*	• Debit the Physical Bilateral Contract Quantity of Energy Sold ($BCQ_{k,b,h}^{m,t}$) at the 5-Minute Energy Market Price within Ontario ($EMP_h^{m,t}$).	• Credit the Physical Bilateral Contract Quantity of Energy Bought ($BCQ_{s,k,h}^{m,t}$) at the *Hourly Ontario Energy Price* (HOEP).	101
Dispatchable *delivery point*	• Debit the Physical Bilateral Contract Quantity of Energy Sold ($BCQ_{k,b,h}^{m,t}$) at the 5-Minute Energy Market Price within Ontario ($EMP_h^{m,t}$).	• Credit the Physical Bilateral Contract Quantity of Energy Bought ($BCQ_{s,k,h}^{m,t}$) at the 5-Minute Energy Market Price within Ontario ($EMP_h^{m,t}$).	100
Intertie Metering Point	• Debit the Physical Bilateral Contract Quantity of Energy Sold ($BCQ_{k,b,h}^{m,t}$) at the 5-minute Energy Market Price at the *Interties* ($EMP_h^{i,t}$).	• Credit the Physical Bilateral Contract Quantity of Energy Bought ($BCQ_{s,k,h}^{m,t}$) at the 5-minute Energy Market Price at the *Interties* ($EMP_h^{i,t}$).	100

These financial credits and debits are then included the overall *settlement amounts* calculated for *charge types* 100 and 101 as per the equations in **Section 2.2**.

2.5.2 The Nature of the Bilateral Contract Quantity

$\mathbf{BCQ_{s,k,h}^{m,t}}$	Physical Bilateral Contract Quantity of Energy bought.	Physical bilateral contract quantity of *energy* in MWh bought by *buying market participant* 'k' from *selling market participant* '*s'* at *RWM* or *intertie metering point* 'm' for each *metering interval* 't' in *settlement hour* 'h'.
$\mathbf{BCQ_{k,b,h}^{m,t}}$	Physical Bilateral Contract Quantity of Energy sold.	Physical bilateral contract quantity of *energy* in MWh sold by *selling market participant* 'k' to *buying market participant* 'b' at *RWM* or *intertie metering point* 'm' for each *metering interval* 't' in *settlement hour* 'h'.

The submission of *physical bilateral contract data* is governed by Section 2.4 of Chapter 8 of the *IESO market rules*. Furthermore, Section 2.3 of Chapter 8 describes 2 distinct "forms" of *physical bilateral contract data* that may be submitted by the *selling market participant*. Specifically, the two forms of such data are as follows:

1. **Absolute quantities:** specifying the absolute quantity of *energy* in MWh sold by the *selling market participant* to the *buying market participant* for each *settlement hour* at a particular *delivery point* or *intertie metering point*; and
2. **Derived quantities****:** specifying that the *physical bilateral contract quantity* shall be 100% of the *energy* sold by the *selling market participant* to the *buying market participant* for each *settlement hour* as derived from a particular *delivery point* value (i.e. NOT an *intertie metering point*).

Where:

- The *delivery point* chosen by the *selling market participant* must belong to either the *selling market participant* or the buying *market participant.*
- If the *delivery point* is designated as a sub-type 'I' (injection) *delivery point*, 100% of all injected *energy* for each *metering interval* in each applicable *settlement hour* shall be used regardless of any *physical allocation data*.
- If the *delivery point* is designated as a sub-type 'W' (withdrawal) *delivery point*, 100% of all withdrawn *energy* for each *metering interval* in each applicable *settlement hour* shall be used regardless of any *physical allocation data*.

***** See derived quantities examples that follow.**

Derived Quantities Example 1: *Delivery point* belongs to the *SELLING market participant* and is a sub-type 'I' (injection) *delivery point.* (note parity with EXAMPLE 3)												
Metering Interval	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
ENERGY QUANTITY	10	10	10	0	0	0	**10**	**10**	0	0	10	10
ENERGY FLOW Injection (I) Withdrawal (W)	I	I	I	I	I	I	**W**	**W**	I	I	I	I
BCQ value used for settlement purposes (for both the buying and selling market participant)	10	10	10	0	0	0	**0**	**0**	0	0	10	10
Total Quantity for the hour	50 (SEE SECTION 2.5.3 FOR THE DATA PRESENTATION OF THE BILATERAL CONTRACT QUANTITY)											

Derived Quantities Example 2: *Delivery point* belongs to the *SELLING market participant* and is a sub-type 'W' (Withdrawal) *delivery point.* (note parity with EXAMPLE 4)												
Metering Interval	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
ENERGY QUANTITY	**10**	**10**	**10**	0	0	0	10	10	0	0	10	10
ENERGY FLOW Injection (I) Withdrawal (W)	**I**	**I**	**I**	W	W	W	W	W	W	W	I	I
BCQ value used for settlement purposes (for both the buying and selling market participant)	**0**	**0**	**0**	0	0	0	10	10	0	0	0	0
Total Quantity for the hour	20 (SEE SECTION 2.5.3 FOR THE DATA PRESENTATION OF THE BILATERAL CONTRACT QUANTITY)											

Derived Quantities Example 3: *Delivery point* belongs to the *BUYING market participant* and is a sub-type 'I' (injection) *delivery point.* (note parity with EXAMPLE 1)												
Metering Interval	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
ENERGY QUANTITY	10	10	10	0	0	0	**10**	**10**	0	0	10	10
ENERGY FLOW Injection (I) Withdrawal (W)	I	I	I	I	I	I	**W**	**W**	I	I	I	I
BCQ value used for settlement purposes (for both the buying and selling market participant)	10	10	10	0	0	0	**0**	**0**	0	0	10	10
Total Quantity for the hour	50 (SEE SECTION 2.5.3 FOR THE DATA PRESENTATION OF THE BILATERAL CONTRACT QUANTITY)											

Derived Quantities Example 4: *Delivery point* belongs to the *BUYING market participant* and is a sub-type 'W' (Withdrawal) *delivery point.* (note parity with EXAMPLE 2)												
Metering Interval	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
ENERGY QUANTITY	**10**	**10**	**10**	0	0	0	10	10	0	0	10	10
ENERGY FLOW Injection (I) Withdrawal (W)	**I**	**I**	**I**	W	W	W	W	W	W	W	I	I
BCQ value used for settlement purposes (for both the buying and selling market participant)	**0**	**0**	**0**	0	0	0	10	10	0	0	0	0
Total Quantity for the hour	20 (SEE SECTION 2.5.3 FOR THE DATA PRESENTATION OF THE BILATERAL CONTRACT QUANTITY)											

2.5.3 Time Resolution of Bilateral Contract Quantities and Rounding

Where a *physical bilateral contract* takes place at a non-dispatchable *delivery point*, the *Physical Bilateral Contract Quantity* of Energy Bought is reported by *settlement hour* as per the *market rules* (because the *Hourly Ontario Energy Price* is applied to this quantity – see Chapter 9, Section 3.3). At the same location however, the 'Physical Bilateral Contract Quantity of Energy Sold' is debited at the 5-minute energy market price. This latter, sold quantity must therefore be divided into 12, equal *metering intervals* (see Chapter 9, Section 3.1.6 of the *market rules*) and rounded to the appropriate number of significant digits (see Section 2.4 of this document). As a result, the summation of these 12, equal quantities may not equal the original, hourly value submitted in some circumstances due to this intermediate rounding. The table below summarizes this phenomenon in terms of the location sub-type and the applicable *charge type* used. The reader is directed to Section 2.4 of this document for further details.

		Location Type	Charge Type	Time Resolution used for Settlements Purposes	Intermediate Rounding Applied within Settlements System?
$\mathbf{BCQ_{s,k,h}^{m,t}}$	Physical Bilateral Contract Quantity of Energy bought.	Dispatchable *Delivery Point* (injection or withdrawal sub-type)	100	by *metering interval*	Yes – See Section 2.4
		Non-Dispatchable *Delivery Point* (injection or withdrawal sub-type)	101	by *settlement hour*	No
		Intertie metering point	100	by *metering interval*	Yes – See Section 2.4
$\mathbf{BCQ_{k,b,h}^{m,t}}$	Physical Bilateral Contract Quantity of Energy sold.	Dispatchable *Delivery Point* (injection or withdrawal sub-type)	100	by *metering interval*	Yes – See Section 2.4
		Non-Dispatchable *Delivery Point* (injection or withdrawal sub-type)	101	by *metering interval*	Yes – See Section 2.4
		Intertie metering point	100	by *metering interval*	Yes – See Section 2.4

2.5.4 Allocation of Hourly Uplift Components Between Buying and Selling Market Participants

Hourly uplift is defined in Section 3.9.1 of Chapter 9 of the *IESO market rules* and may be "disaggregated" (sic) on *settlement statements* into its component parts as per Section 3.9.2. The following components *hourly uplift* charges may be allocated from the *buying market participant* to the *selling market participant* as per the *physical bilateral contract data* submitted by the *selling market participant* (see also, *IESO market rules*, Chapter 8, Section 2.2.2).

Hourly Uplift Component Group	Associated Charge Types	Comments
Net Energy Market Settlement Credit (NEMSC) Hourly Uplift Component (also known as the "Losses" component)	150	• This hourly uplift component is an aggregation of *charge types* 100 (NEMSC), 101 (NEMSC), 104 (TRSC), and 103 (TCRF),. The aggregation of these *charge types* mathematically resolves down to the value of the difference between AQEI, AQEW, SQEW and SQEI quantities valued at the 5-minute Energy Market Reference Price ($EMP_h^{REF,t}$) for each *metering interval* in the *settlement hour* .
Operating Reserve Settlement Credit (ORSC) Hourly Uplift Component	250 252 254	• Separate *charge types* for recovery of ORSC *settlement amounts* paid to *market participants* for each class of *operating reserve.*
Intertie Failure Charge Rebate (IFCR) Hourly Uplift Component	186	Two components as follows: 1) *Charge type* 186: an aggregation of *charge types* 135 (Real-time Import Failure Charge), 136 (Real-time Export Failure Charge), 1134 (Day-Ahead Linked Wheel Failure Charge, 1135 (Day-Ahead Import Failure Charge) and 1136 (Day-Ahead Export Failure Charge). These *charge types* are primarily rebates back to *market participants* for amounts collected under these charges.
Congestion Management Settlement Credit (CMSC) Hourly Uplift Component	155	• Includes recovery of CMSC payments for *energy* and each class of *operating reserve.*

Hourly Uplift Component Group	Associated Charge Types	Comments
Transmission Rights Settlement Credit (TRSC) Hourly Uplift Component	NOT USED	• INCLUDED WITH THE "NET ENERGY MARKET SETTLEMENT CREDIT (NEMSC) Hourly Uplift COMPONENT". • SEE NOTE ABOVE.
Transmission Charge Reduction Fund (TCRF) Hourly Uplift Component	NOT USED	• INCLUDED WITH THE "NET ENERGY MARKET SETTLEMENT CREDIT (NEMSC) Hourly Uplift COMPONENT". • SEE NOTE ABOVE.
Operating Reserve Shortfall Settlement Debit (ORSSD) Hourly Uplift Component	201 203 205	• Separate *charge types* for distribution of ORSSD *settlement amounts* received from *market participants* for shortfalls in the provision of each class of *operating reserve.*

Each hourly uplift component group (i.e. not the individual *charge types* themselves) may be selected in any combination when the *physical bilateral contract data* is submitted by the *selling market participant*. Confirmation of this selection is included within the *settlement statement* supporting data files (type "B" records). A schematic overview of the format of type "B" records may be found within Table 3-2 of the *IESO's* Technical Interface Document entitled, "Format Specification for Settlement Statement Files and Data Files".

The effect of selecting an hourly uplift component group within *physical bilateral contract data,* is the creation of a "Reallocate Quantity (RQ)".

The RQ specific to a single *physical bilateral contract* is exactly equal to the quantity of *energy* involved in the contract itself.

The RQ specific to a single *market participant* is equal to the sum of all RQ quantities for which the *market participant* is the *selling market participant*, minus the sum of all RQ quantities for which the *market participant* is the *buying market participant*.

The RQ specific to a single *market participant* for a particular hourly uplift component group is equal to the sum of all RQ quantities designated to for that particular hourly uplift component group within *physical bilateral contract data* for which the *market participant* is the *selling market participant*, minus the sum of all RQ quantities for which the *market participant* is the *buying market participant*.

This RQ quantity is then applied to the calculation of the *settlement amounts* for each *charge type* associated with the hourly uplift component group as per the table above.

Therefore, when calculating the RQ quantity for a particular hourly uplift *charge type* for *market participant* 'k' at a particular location 'm' during a particular *metering interval* 't', the quantity may be expressed as follows:

$$RQ_{k,h}{}^{m,t} = \sum_{s,b}\left[BCQ_{k,b,h}{}^{m,t} - BCQ_{s,k,h}{}^{m,t}\right]$$

Where all variables are defined as per **Section 2.1**.

The RQ quantity is then used to either augment or decrease the *settlement amount* for the hourly uplift *charge type* "c" as follows:

$$\sum_c{}^{M,T} TD_{k,h,c} \times [(AQEW_{k,h}{}^{m,t} + SQEW_{k,h}{}^{i,t} + RQ_{k,h}{}^{m,t}) / \sum_k{}^{M,T} (AQEW_{k,h}{}^{m,t} + SQEW_{k,h}{}^{i,t})]$$

Where all variables are defined as per **Section 2.1**.

In the event that the term,

$$(AQEW_{k,h}{}^{m,t} + SQEW_{k,h}{}^{i,t} + RQ_{k,h}{}^{m,t}) < 0$$

Where:

$$RQ_{k,h}{}^{m,t} < 0 \text{ and } |RQ_{k,h}{}^{m,t}| > |(AQEW_{k,h}{}^{m,t} + SQEW_{k,h}{}^{i,t})| \text{ and } TD_{k,h,c} > 0$$

The calculation of the applicable hourly uplift charge type "c" will yield a net credit to the *buying market participant* as a result of the reallocated quantity exceeding their actual/scheduled withdrawals of *energy* for the *metering interval* 't' in question.

The above mechanism applies to those "associated charge types" that are enumerated in the table at the beginning of this Section. See Section 2.2 for specific listings of *charge types* and their respective equations.

2.6 Exemptions from the Day-Ahead Import Failure Charge, Day-Ahead Export Failure Charge, and Day-Ahead Linked Wheel Failure Charge

2.6.1 Purpose of this Section

This section describes how Day-Ahead Import transactions are subject to an "*Offer* Price Test" in order to determine if they are exempt from the Day-Ahead Import Failure Charge (*charge type* 1135), Day-Ahead Export Failure Charge (*charge type* 1136) and Day-Ahead Linked Wheel Failure Charge (*charge type* 1134)2.

Generally speaking the applicability of the five Intertie Failure charges3 is affected by the "Reason Codes" attached to the applicable *interchange schedule* received by the *Settlement Process*. The impact of these Reason Codes is outlined in Table 3-5 of the *IESO* Technical Interface document entitled, "Format Specifications for Settlement Statement Files and Data Files" (IMP_SPEC_0005). As noted in that table however, day-ahead import transactions arranged in the *pre-dispatch-of-record* that include the 'AUTO''NY90' or 'ADQh', or 'ORA' Reason Codes in the resulting real-time dispatch will be further subject to an "Offer Price Test" which determines whether or not the transaction in question is in fact exempt from the Day-Ahead Failure Charges.

2.6.2 Objective of the "Offer Price Test"

The main objective of the Offer Price Test is to grant an exemption from the DA-IFC, DA-EFC and DA-LWFC for those import and export transactions that make a best effort to ensure that they are scheduled in the *real-time market*. The Offer Price Test assesses "best effort" on the basis of the offer price of the transaction itself.

2.6.3 How the Offer Price Test Works

The Offer Price Test is a simple test that is performed on the first lamination of the *real-time market* import *offer*/or export *bid*. The "first lamination" is defined by the first two *price-quantity* ("p-q") *pairs* in the *real-time market offer* curve, where:

2 The price test for the Day-Ahead Linked Wheel Failure Charge (1134) is used to determine exemption from the RT-EFC-DALW and RT-IFC-DALW portions only.

3 Specifically, the Real-time Import Failure Charge (*charge type* 135), the Real-time Export Failure Charge (*charge type* 136), the Day-Ahead Import Failure Charge (*charge type* 1135), the Day-Ahead Export Failure Charge (*charge type* 1136) and the Day-Ahead Linked Wheel Failure Charge (*charge type* 1134).

- The first *price-quantity pair* contains an *offer* or *bid* price and a quantity of zero; and
- The second *price-quantity pair* contains the same *offer* or *bid* price as the first *price-quantity pair* and a non-zero quantity.

The Offer Price Test applies to any situation in which a day-ahead import or export transaction has a Reason Code, 'AUTO', 'NY90' 'ADQh', or 'ORA' assigned to the corresponding real-time import or export transaction at the same location. It is applicable to *any intertie metering point* where the underlying constrained scheduling point (CSP) is a "source" (i.e. applicable to imports only) or a "sink" (i.e. applicable to exports only).

If the transaction fails this test; it will not receive exemption status from the DA-IFC or DA-EFC. If the transaction passes this test, then it will be exempted from the DA-IFC or DA-EFC – without actually changing the Reason Code itself.

2.6.4 Input Data:

$DA_DQSI_{k,h}^{i,t}$	=	Day-ahead constrained quantity scheduled for injection by *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h'
$PD_DQSI_{k,h}^{i,t}$	=	*Pre- dispatch* constrained quantity scheduled for injection by *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h'.
$PD_BE_{k,h}^{i,t}$	=	*Energy offers* submitted in Pre-dispatch, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered price in each *price quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2
- MMCP	=	The *Minimum Market Clearing Price*.
$DA_DQSW_{k,h}^{i,t}$		Day-ahead constrained quantity scheduled for withdrawal by *market participant* 'k' at *intertie metering point* 'i' during metering interval 't' of settlement hour 'h'
$PD_DQSW_{k,h}^{i,t}$		*Pre- dispatch* constrained quantity scheduled for withdrawal by *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h'.

$PD_BL_{k,h}^{i,t}$		*Energy bids* submitted in *pre-dispatch*, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered price in each *price quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2
+MMCP	=	The *Maximum Market Clearing Price*.

2.6.5 Decision Logic Applied During the Offer Price Test for Import Transactions:

PART 1:

The first part of the test ensures that the original *schedule-of-record* schedule ($DA_DQSI_{k,h}^{i,t}$) for the import transaction is indeed GREATER THAN the resulting *Pre-dispatch schedule* ($PD_DQSI_{k,h}^{i,t}$) over the course of *settlement hour* 'h'.

IF $\sum^{T} DA_DQSI_{k,h}^{i,t} > \sum^{T} PD_DQSI_{k,h}^{i,t}$

THEN

Proceed to PART 2

ELSE

END of the test for this transaction.

PART 2:

The second part of the test ensures that the first lamination (i.e. as defined by the first 2 *price-quantity pairs*) of the offer curve submitted into the *pre-dispatch scheduling process*:

1) Was large enough to cover the entire quantity of the transaction originally scheduled by the *schedule-of-record* at the same *market participant/intertie metering point* combination (commonly referred to as a "MP/MSP/CSP triplet"); and,
2) Was offered at the *Minimum Market Clearing Price* (*-MMCP*).

The test is as follows:

For each *metering interval* 't' at *intertie metering point* 'i' where the transaction passed PART 1 for *settlement hour* 'h':

Let 'B' be matrix $PD_BE_{k,h}^{i,t}$ (see above for definition).

IF B[2,2] ≥ $DA_DQSI_{k,h}^{i,t}$ AND B[2,1] = -MMCP

THEN

Allow Reason Code to remain as-is, but exempt the transaction from the DA-IFC.

ELSE

Allow Reason Code to remain as-is, and do NOT exempt the transaction from the DA-IFC.

Implications:

- A day-ahead import transaction must be constrained down to a level lower than its original *schedule-of-record* schedule in order to receive exemption status;
- The entire amount of the constrained portion of the transaction must have been offered into the *Pre-dispatch* at *–MMCP* in order to receive exemption status (compare Figures 2-1 and 2-2 to see examples where this condition is met and not met respectively); and
- Only the first lamination (i.e. the first 2 p-q pairs) of the Pre-dispatch offer curve for each import transaction are relevant in performing this test (due to the existing market rule requirement that offer prices must be monotonically increasing).

2.6.6 Decision Logic Applied During the Offer Price Test for Export Transactions:

PART 1:

The first part of the test ensures that the original *schedule-of-record* ($DA_DQSW_{k,h}^{i,t}$) for the export transaction is indeed GREATER THAN the resulting *Pre-dispatch schedule* ($PD_DQSW_{k,h}^{i,t}$) over the course of *settlement hour* 'h'.

IF $\sum^{T} DA_DQSW_{k,h}^{i,t} > \sum^{T} PD_DQSW_{k,h}^{i,t}$

THEN

Proceed to PART 2

ELSE

END of the test for this transaction.

PART 2:

The second part of the test ensures that the first lamination (i.e. as defined by the first 2 *price-quantity pairs*) of the offer curve submitted into the *Pre-dispatch scheduling process*:

1) Was large enough to cover the entire quantity of the transaction originally scheduled by the *schedule-of-record* at the same *market participant/intertie metering point* combination (commonly referred to as a, "MP/MSP/CSP triplet"); and,
2) Was offered at the *Maximum Market Clearing Price* (+*MMCP*).

The test is as follows:

For each *metering interval* 't' at *intertie metering point* 'i' where the transaction passed PART 1 for *settlement hour* 'h':

Let 'B' be matrix $BL_{k,h}^{i,t}$ (see above for definition).

IF B[2,2] ≥ $DA_DQSW_{k,h}^{i,t}$ AND B[2,1] = +MMCP

THEN

Allow Reason Code to remain as-is, but exempt the transaction from the DA-EFC.

ELSE

Allow Reason Code to remain as-is, and do NOT exempt the transaction from the DA-EFC.

Implications:

- A day-ahead export transaction must be constrained down to a level lower than its original *schedule-of-record* in order to receive exemption status;
- The entire amount of the constrained portion of the transaction must have been offered into the *Pre-dispatch* at *+MMCP* in order to receive exemption status (compare Figures 2-1 and 2-
- 2 to see examples where this condition is met and not met respectively); and
- Only the first lamination (i.e. the first 2 p-q pairs) of the Pre-dispatch offer curve for each export transaction are relevant in performing this test (due to the existing *market rule* requirement that *offer* prices must be monotonically decreasing).

2.6.7 Decision Logic Applied During the Offer Price Test for Linked Wheel Transactions:

The test seeks to demonstrate a best efforts attempt to schedule both the import and export legs of a day-ahead linked wheel (DALW) transaction through both:

- A Pre-dispatch bid at positive maximum market clearing price (+MMCP) for a quantity at least equal to the day-ahead export quantity, and
- A Pre-dispatch offer at negative maximum market clearing price (–MMCP) for a quantity at least equal to the day-ahead import quantity.

For import leg of the linked wheel, the decision logic for the price test is described in Section 2.6.5 with the following amendment:

For each *metering interval* 't' at *intertie metering point* 'i' where the transaction passed PART 1 for *settlement hour* 'h':

Let 'B' be matrix $PD_BE_{k,h}^{i,t}$ (see above for definition).

IF B[2,2] ≥ $DA_DQSI_{k,h}^{i,t}$ AND B[2,1] = -MMCP

THEN

Allow Reason Code to remain as-is, but exempt the transaction from the **RT-IFC-DALW**.

ELSE

Allow Reason Code to remain as-is, and do NOT exempt the transaction from the **RT-IFC-DALW**.

For export leg of the linked wheel, the decision logic for the price test is described in Section 2.6.6 with the following amendment:

For each *metering interval* 't' at *intertie metering point* 'i' where the transaction passed PART 1 for *settlement hour* 'h':

Let 'B' be matrix $BL_{k,h}^{i,t}$ (see above for definition).

IF $B[2,2] \geq DA_DQSW_{k,h}^{i,t}$ AND $B[2,1] = +MMCP$

THEN

Allow Reason Code to remain as-is, but exempt the transaction from the **RT-EFC-DALW**.

ELSE

Allow Reason Code to remain as-is, and do NOT exempt the transaction from the **RT-EFC-DALW**.

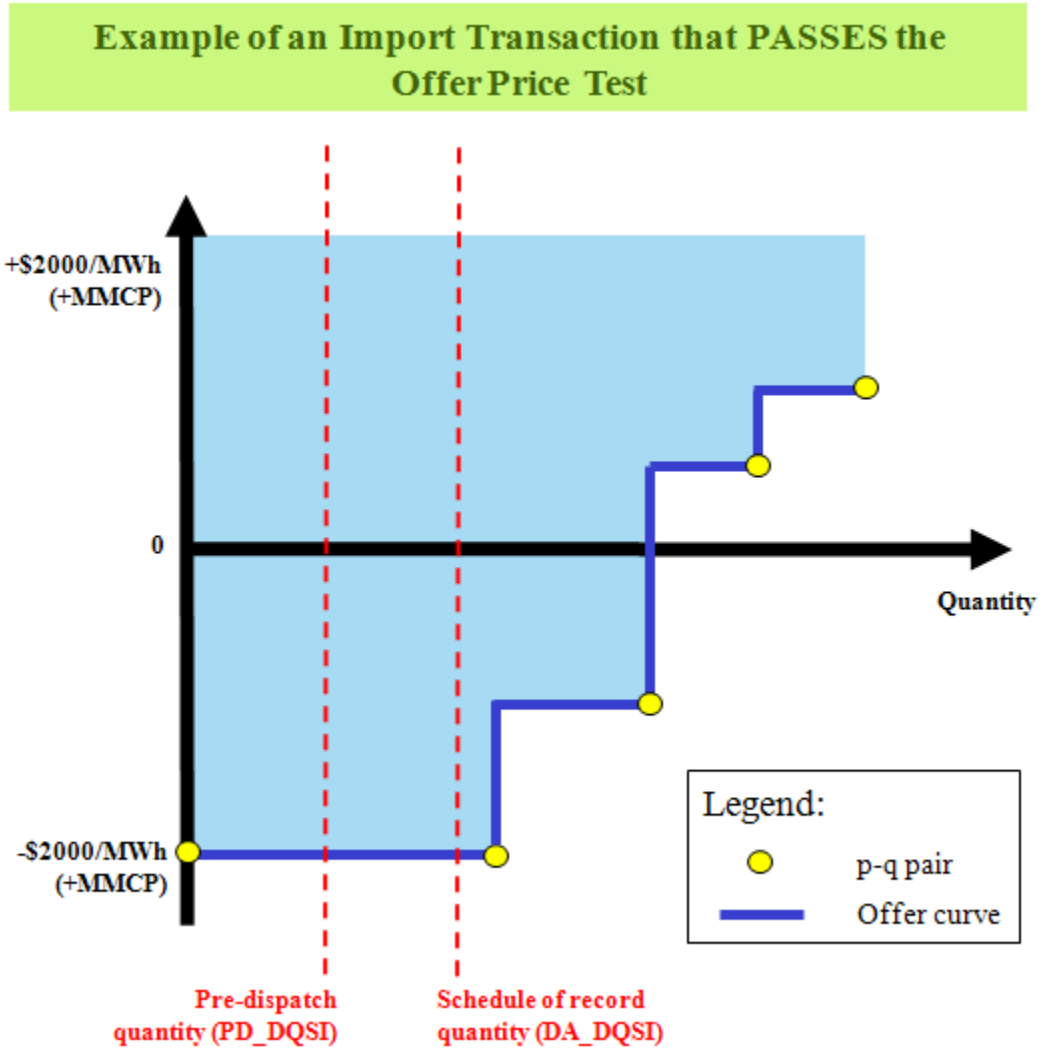


Figure 2-1 – Example of an Import Transaction that PASSES the "Offer Price Test"

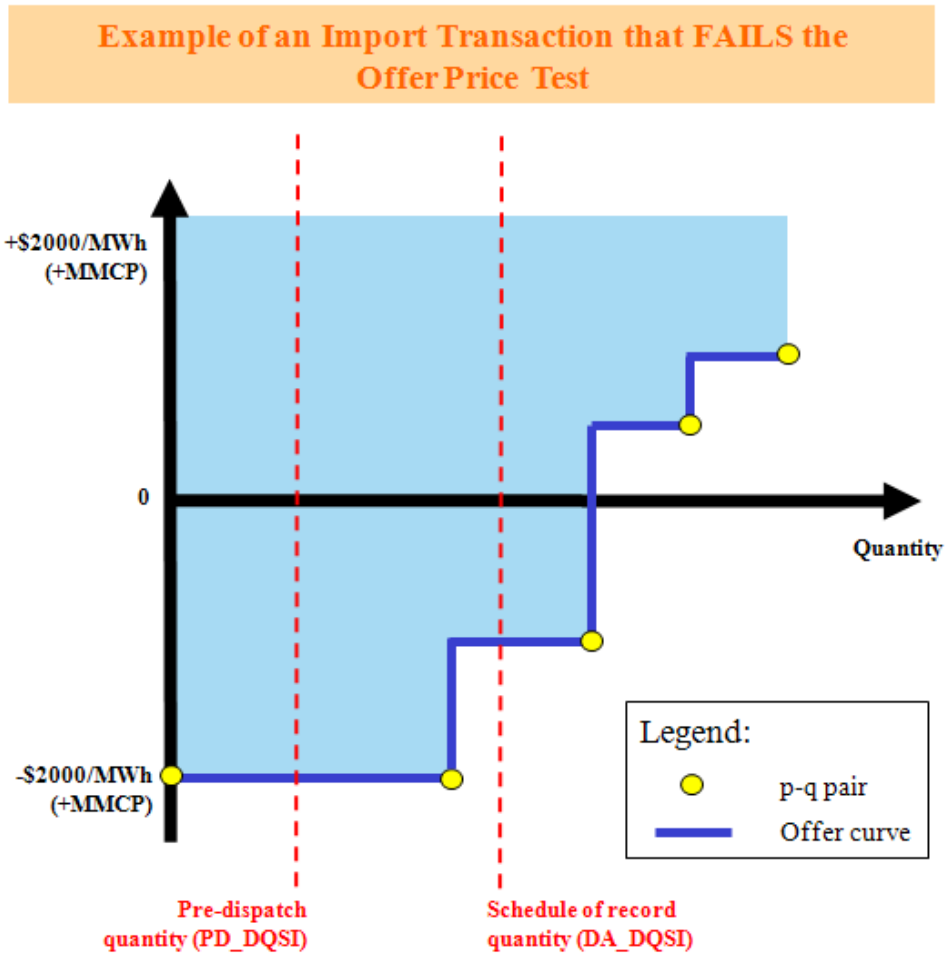


Figure 2-2 – Example of an Import Transaction that FAILS the "Offer Price Test"

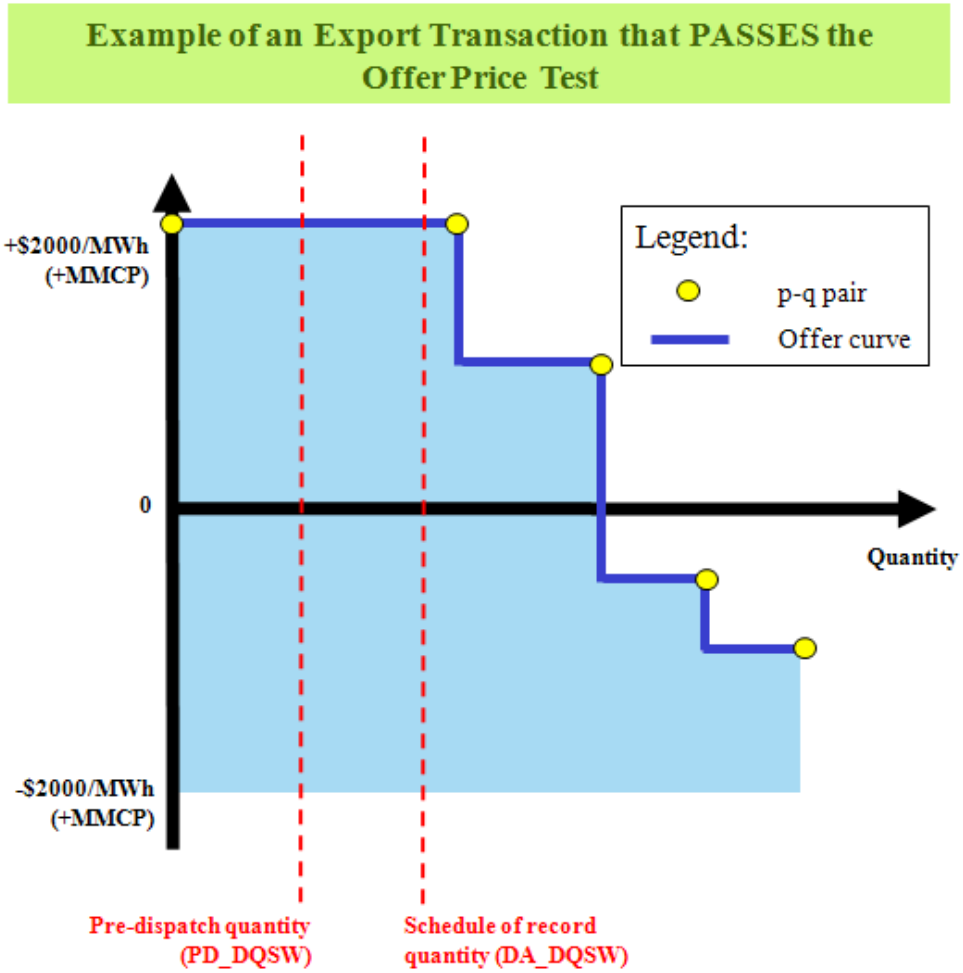


Figure 2-3 – Example of an Export Transaction that PASSES the "Offer Price Test"

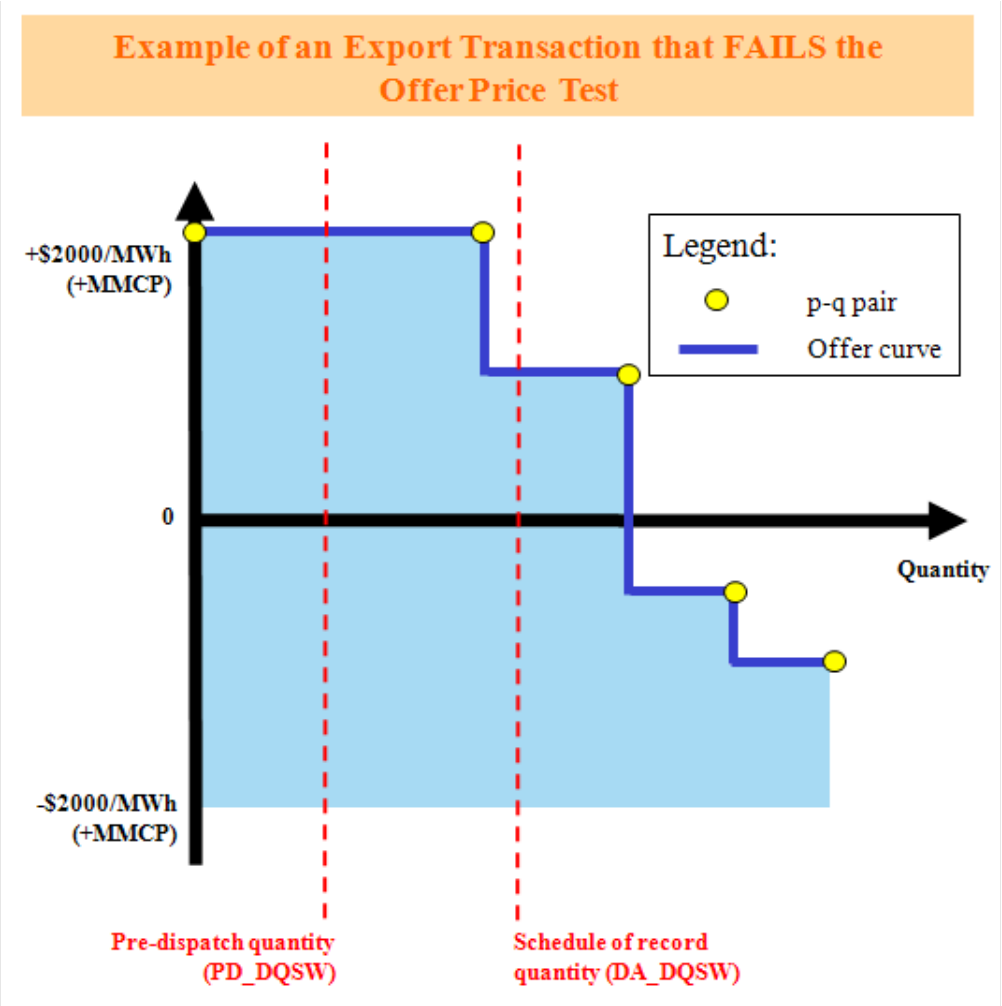


Figure 2-4 – Example of an Export Transaction that PASSES the "Offer Price Test"

- End of Section -

References

Document Name	Doc ID
Market Rules	MDP_RUL_0002
Format Specification for Settlement Statement Files and Data Files	IMP_SPEC_0005
Ontario Energy Board: Ontario Transmission Rate Schedules EB-2007-0759	EB-2007-0759
Order-in-Council 137/2008 Ontario Power Generation Rebate	OIC 137/2008
Ontario Regulation 442/01 "Rural or Remote Electricity Rate Protection	442/01
Ontario Regulation 493/01 "Debt Retirement Charge – Rates and Exemptions"	493/01
Ontario Regulation 494/01 "Debt Retirement Charge Administration"	494/01
Legislative Assembly of Ontario S.O. 2003, Chapter 8 "Bill 4, An Act to amend the *Ontario Energy Board Act, 1998* with respect to electricity pricing." **Royal Assent:** December 18, 2003	Bill 4
Regulations made pursuant to Bill 4 Ontario Regulation 42/04 made under the *Ontario Energy Board Act, 1998*. Ontario Regulation 43/04 made under the *Ontario Energy Board Act, 1998*.	42/04 43/04
Legislative Assembly of Ontario, Bill 210 – "Electricity Pricing, Conservation and Supply Act, 2002." S.O. 2002, Chapter 23 **Formal Title:** "An Act to amend various Acts in respect of pricing, conservation and supply of electricity an in respect of other matters related to electricity." **Royal Assent:** December 9, 2002	Bill 210
Regulations made pursuant to BILL 210 "Electricity Pricing, Conservation and Supply Act, 2002." **Regulation 339/02** (Under the *Ontario Energy Board Act, 1998*) "Electricity Pricing" – amended by regulation 433/02	339/02 (amended by 433/02) 341/02 (amended by 434/02) 342/02 (revoked by 432/02) 433/02

Document Name	Doc ID
Regulation 341/02 (Under the *Ontario Energy Board Act, 1998*) "Compensation and Set-Offs Under Part V of the Act" – amended by regulation 434/02 **Regulation 342/02** (Under the *Ontario Energy Board Act, 1998*) "Payments to the IMO" – revoked by regulation 432/02 **Regulation 432/02** (Under the *Ontario Energy Board Act, 1998)* "Revoking Ontario Regulation 342/02 (Payments to the IMO)" **Regulation 433/02** (Under the *Ontario Energy Board Act, 1998*) "Amending Ontario Regulation 339/02 (Electricity Pricing)" **Regulation 434/02** (Under the *Ontario Energy Board Act, 1998)* "Amending Ontario Regulation 341/02 (Compensation and Set-Offs Under Part V of the Act)" **Regulation 435/02** (Under the *Ontario Energy Board Act, 1998*) "Payments re Section 79.4 of the Act" **Regulation 436/02** (Under the *Ontario Energy Board Act, 1998*) "Payments re Various Electricity-Related Charges" **Regulation 330/09** (Under the *Ontario Energy Board Act, 1998*) "Cost recovery re section 79.1 of the Act"	434/02 435/02 436/02 330/09
***Ontario Energy Board*, *Independent Electricity Market Operator* Licence EI-2003-0088, issued on July 30, 2003**	**EI-2003-0088**
Legislative Assembly of Ontario, Bill 100 – "Electricity Restructuring Act, 2004" **Royal Assent:** December 9, 2004 Subject to regulations made pursuant to the "Electricity Restructuring Act, 2004" once proclaimed into force: Ontario regulation 427/04 "Payments to the Financial Corp. re Section 78.2 of the Act" Ontario regulation 428/04 "Payments re Section 79.4 of the Act" Ontario regulation 398/10 Amending Ontario regulation 429/04 "Adjustments Under Section 25.33 of the Act" Ontario regulation 430/04 "Payments re Section 25.33 of the Act" Ontario regulation 431/04 "Payments re Section 25.34 of the Act" Section 78.3 of the (Ontario Energy Board) Act Section 78.4 of the (Ontario Energy Board) Act Section 78.5 of the (Ontario Energy Board) Act	BILL 100 See also, Ontario e-laws website for official Ontario Government Regulation ID numbers at: http://www.e-laws.gov.on.ca

Document Name	Doc ID
Ontario regulation 53/05 made under *OEB Act, 1998* re "Payments under Section 78.1 of the Act" Ontario regulation 98/05 made under *OEB Act, 1998* re "Payments re Various Electricity-Related Charges" Ontario Regulation 66/10 made under *OEB Act, 1998* re "Assessments for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program Costs"	BILL 100 See also, Ontario e-laws website for official Ontario Government Regulation ID numbers at: http://www.e-laws.gov.on.ca/
Ontario Clean Energy Benefit Act, 2010, Ontario Regulation 495/10.	
Ontario Regulation 314/15 "Ontario Electricity Support Program"	314/15
Ontario Regulation 363/16 made under "Ontario Rebate for Electricity Consumers Act, 2016".	363/16
Ontario Regulation 364/16 made under "Ontario Rebate for Electricity Consumers Act, 2016".	364/16

– End of Document –

Exhibit “S”

IESO stakeholder engagement slide deck dated May 22, 2024

Exhibit “S”

to the Affidavit of Robin Doolittle

Sworn before me on October 29, 2025, in accordance with O. Reg. 431/20, Administering Oath or Declaration Remotely



Commissioner for Taking Affidavits
(or as may be)

October 29, 2025

Keith Edward Hickey, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.

Expires June 24, 2027.

A1423

MAY 22 2024

Interchange schedule code: MrNH

IESO May Stakeholder Engagement Session



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Agenda

1. Introduction
2. What are interchange schedule codes?
3. Review identified issues with MrNH code
4. Review proposed change to MrNH code

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What are Interchange Schedule Codes?

- When scheduled interchange transactions differ from actual real-time flow, specific codes are used to identify the reason for these discrepancies.
- These codes categorize intertie transaction failures and curtailments based on specific reasons which then drive settlement outcomes.

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Intertie Failures

DSO* determines intertie transactions MW amounts for next hour

Intertie transactions amounts are fixed in real time

Hour-ahead Pre-dispatch | **Real time hour**

- Difference between hour-ahead pre-dispatch scheduled interchange transaction flows and real-time flows is considered an interchange transaction failure.
- Interchange transactions fail to flow for a variety of reasons.

* Dispatch Scheduling and Optimization

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Application of Failure Charges

- Intertie transactions that fail for reasons within the control of the market participant are not exempt from failure charges.
- Intertie transactions that fail for reasons outside the control of the market participant or due to the actions of IESO or other jurisdictions are exempt from settlement charges.
- Market Manual 4.3 further outlines specific reasons, supported by Market Rules, which the IESO has determined to by default to be bona fide and legitimate.

Market Rules Chapter 7.5.8B [1]

Failed transactions will incur a failure charge "…other than for bona fide and legitimate reasons as determined by the IESO. Bona fide and legitimate reasons shall include failures caused by actions and circumstances beyond the control of the market participant or due to IESO or external scheduling entity error or action, including those reasons specified in the applicable market manual."

1. Market Rule Chapter 7 System Operations and Physical Markets

Market Manual 4: Interchange schedule codes

In Market Manual Part 4.3: Real-Time Scheduling of the Physical Markets, Table 6-1: Application of Interchange Schedule Codes shows the following codes and associated treatments.

These codes categorize intertie transaction failures and curtailments based on specific reasons which then drive appropriate settlement outcomes.

Shown here is the array of codes and how failure charges are applied.

Code	DA intertie failure charge	RT intertie failure charge
OTH	Yes	Yes
TLRe	No	No
TLRi	No	No
ORA	No	No
MrNH	Yes (import only)	No
ADQh	No	No
NY90	No	No

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MrNH Code (MISO Ramp/New York HAM)

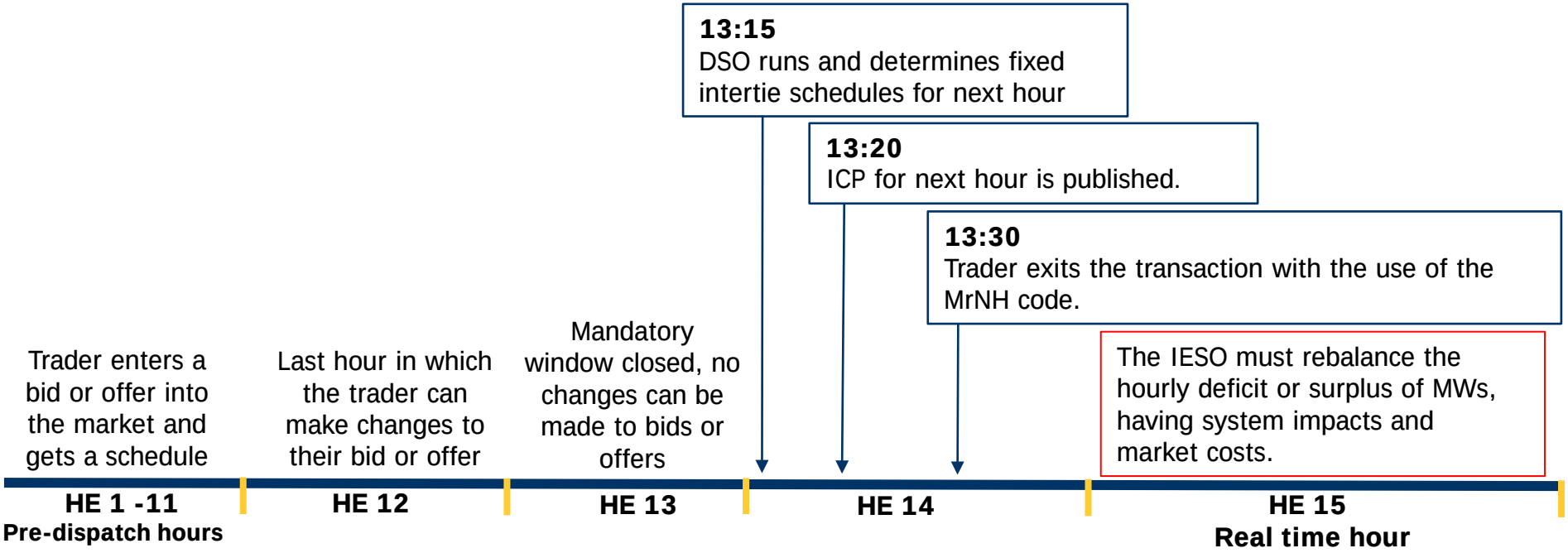
As described in Market Manual 4.3, MrNH is currently applied to intertie transactions that fail due to three specific reasons:

1. Inability of market participant to acquire transmission service from MISO,
2. Inability of market participant to acquire ramp capacity from MISO,
3. Inability of market participant to be scheduled in NYISO Hour Ahead Market (HAM).

MrNH failures are currently only subject to Day-Ahead (DA) Intertie Failure Charges on imports and are exempt from all other charges.

MrNH Timeline Example

This example outlines a timeline of how MrNH is typically applied.



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Issues identified with MrNH

- The preview of intertie congestion price (ICP) combined with the absence of financial penalty does not create the right incentives.
  - Preview of ICP provides information of potential real time spread.
  - This may provide incentive to purposely fail the transactions when financially advantageous to do so.
- Failed intertie transactions through MrNH are being charged to Ontario ratepayers through an uplift.

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MrNH Import Example

13:15
DSO runs and determines 100 MW fixed import schedule for next hour

13:20
ICP for next hour is published.

13:30
Trader exits the transaction with the use of the MrNH code

The missing 100 MW of imports is now a **deficit** of 100 MW in Ontario

IMPACT

IESO

- **System impact:** The IESO may have to constrain on generation to adjust for the unexpected deficit.
- **Inefficient scheduling:** Failed transaction may have displaced a transaction that would have otherwise flowed.

Ratepayers

- Resulting actions may increase in market costs though **uplifts or higher prices.**
- Unfunded congestion in the Transmission Rights (TR) clearing account.

Trader

- **No financial penalty** impact.
- May have contributed to congestion but is not impacted by it as the import did not flow in RT.

HE 14 | **HE 15: Real-time hour**

MrNH Export Example

13:15
DSO runs and determines 100 MW fixed export schedule for next hour.

13:20
ICP for next hour is published.

13:30
Trader exits the transaction with the use of the MrNH code.

The missing 100 MW of export is now a **surplus** of 100 MW in Ontario

HE 14

HE 15: Real-time hour

IMPACT

IESO

- **System Impact:** The IESO must constrain-off generation or imports to adjust for the unexpected surplus, potentially impacting baseload generation during low demand periods.
- **Inefficient scheduling**: Failed transaction may have displaced a more economic transaction that would have otherwise flowed.

Ratepayers

- Resulting actions may increase in market costs though **uplifts.**
- Unfunded congestion in the Transmission Rights (TR) clearing account
- **Forgone energy** of constrained-off generation is paid for by the ratepayer through global adjustment.

Trader

- **No financial penalty** impact.
- May have contributed to congestion but does not pay its share as it did not flow in RT.

Summary of Impacts

- Failures cause system impacts and market inefficiency.
- Ratepayers are shouldering the financial impact of failures when traders delay cancellation until the final moments, despite their earlier awareness of ramp and transmission status.
- Post MRP, these issues of market inefficiency, system impacts, and uncompensated cost of congestion persist and can potentially be amplified.
- Financial incentives to intentionally fail will become more significant with the introduction of the Day-Ahead Market.

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Proposed change – Re-code MrNH failures

- Intertie failures due to the lack of MISO transmission or ramp will be recoded as OTH.

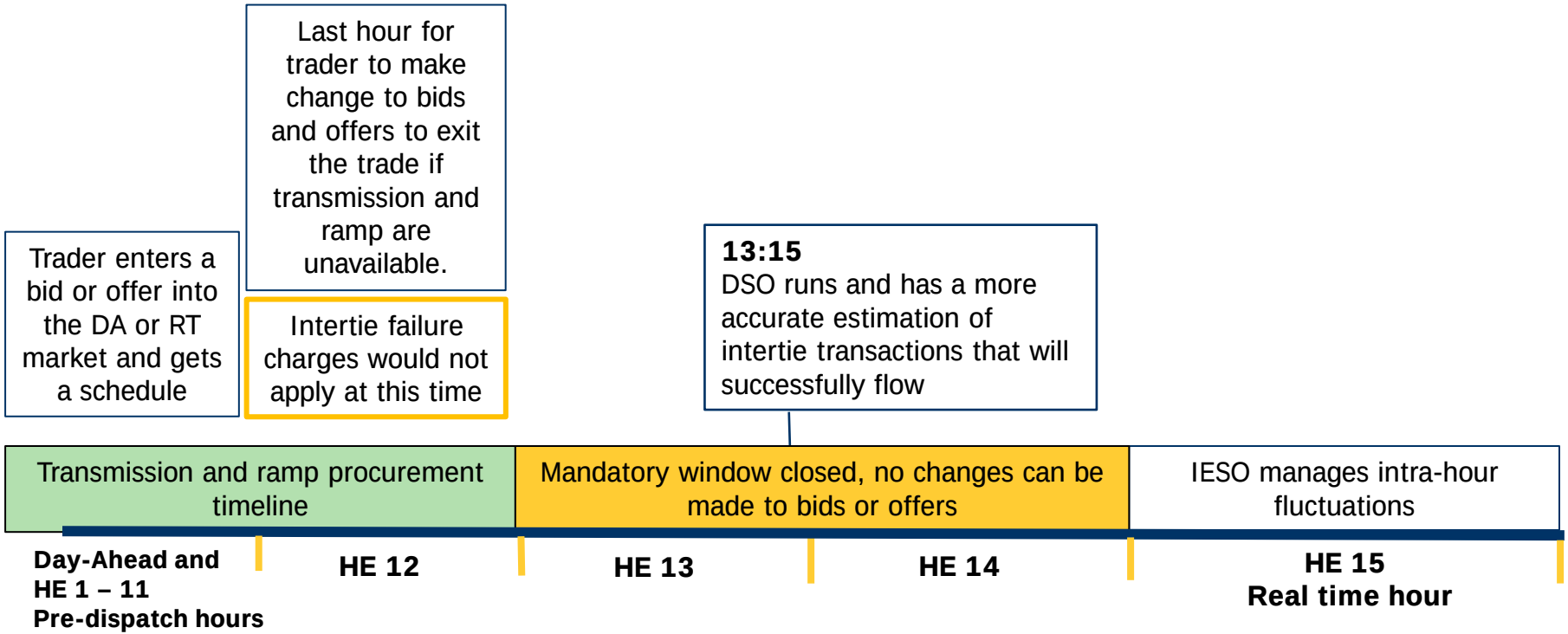
- Market participants will be subject to an intertie failure charge if unable to acquire ramp or transmission service from MISO prior to 30 minutes before the dispatch hour.

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Rationale for change

- Charging the IFC is consistent with the practice of other jurisdictions due the failure of acquiring ramp and transmission.
- Greater likelihood of more operationally feasible schedules.
- Acquiring ramp and transmission and navigating through the market is the market participant's responsibility.
- Discourages market participants from failing transactions at the last minute by applying a financial charge.
- Any failed transactions are charged back to the market participant responsible for the failed transaction instead of being charged to ratepayers through an uplift.
- This is an issue that exists today and would carry through in MRP. That is why we are addressing it now.

Optimal Scheduling with Proposed Change



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Feedback and Next Steps

- The IESO is seeking stakeholder feedback on the proposed change.

- Market Manual amendments will be applied to an upcoming baseline
    - Participants will be notified via IESO Bulletin and on Engagement page.
    - Amendments will be posted for review and feedback.

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Thank You

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Exhibit "T"

IESO Interjurisdictional Energy Trading training guide dated January 2014

Exhibit "T"

to the Affidavit of Robin Doolittle

Sworn before me on October 29, 2025, in accordance with O. Reg. 431/20,
Administering Oath or Declaration Remotely



Commissioner for Taking Affidavits
(or as may be)

October 29, 2025

Keith Edward Hickey, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.

Expires June 24, 2027.

A1441

Interjurisdictional Energy Trading

IESO TRAINING

Revised: January 2014

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Introduction to Interjurisdictional Energy Trading

AN IESO TRAINING PUBLICATION

This document has been prepared to assist in the IESO's training of market participants and has been compiled from extracts from the market rules or documents posted on the web site of Ontario's Independent Electricity System Operator. Users are reminded that they remain responsible for complying with all of their obligations under the market rules and associated policies, standards and procedures relating to the subject matter of this document, even if such obligations are not specifically referred to herein. While every effort has been made to ensure the provisions of this document are accurate and up to date, users must be aware that the specific provisions of the market rules or particular document shall govern.

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1. Introduction

The IESO-controlled grid is connected to five neighbouring jurisdictions with intertie transmission lines. These lines allow Ontario to import and export energy. This workbook introduces the basic concepts of Interjurisdictional Energy Trading (IJT) in the IESO-administered markets.

NOTE: This workbook does not include information on interjurisdictional energy trading under the Day-Ahead Commitment Process (DACP). For information on the DACP, please refer to:

- DACP recorded presentations, available on the Training web pages
- 'Guide to the Day-Ahead Commitment Process', available on the Training web pages
- Market Manuals 9.0 through 9.5 concerning the DACP, available on the Rules, Manuals and Forms web pages

Prerequisite

To benefit from this module, you need an understanding of how Ontario's physical markets work. You can gain this understanding by reading *Introduction to Ontario's Physical Markets,* available on the Training home page.

Objectives

After completing this course you will be able to:

- List the markets in which importers and exports can participate
- List the three types of import/export transactions and relate them to transactions within Ontario
- Distinguish between Ontario prices and prices used for imports and exports
- Explain the impact imports and exports have on Ontario prices
- Explain how prices are set for imports and exports
- Explain how imports and exports are scheduled
- Explain how congestion management settlement credits are calculated for intertie transactions
- Calculate intertie offer guarantee (IOG) payments
- Explain the application of the net interchange schedule limit
- Discuss the settlements process and associated charge types
- Explain schedule compliance requirements and potential failure charges

2. Interjurisdictional Energy Transactions

Moving energy across intertie transmission lines to or from other control areas is referred to as interjurisdictional energy trading (IJT). Market participants wishing to conduct IJT can participate in both the real-time energy and operating reserve markets in Ontario. While interjurisdictional transactions are similar to transactions within Ontario, there are significant differences. These differences will be explained in this document.

Objectives

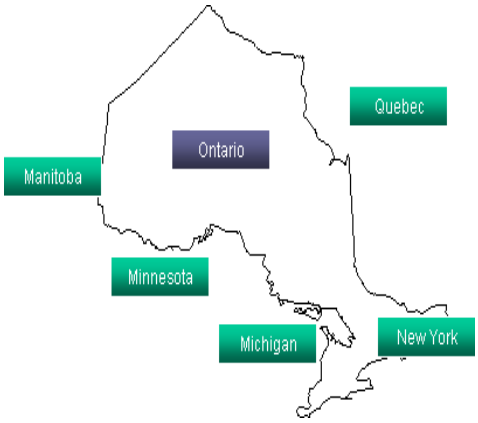
When you have completed this chapter you will be able to:

- List the adjacent control areas available for interjurisdictional trade
- Explain the types of interjurisdictional transactions
- Explain when interchange schedules are determined and why this is different from when schedules for facilities within Ontario are set

Interties

Ontario is interconnected with five other jurisdictions (or “control areas”):

- Manitoba
- Minnesota
- Michigan
- New York
- Quebec



Interties are transmission lines that allow energy to move between adjacent balancing authorities. Like any transmission line, interties can carry only so much energy. Exceeding this level can result in reliability issues such as overheating.

Ontario’s IESO and our interconnected partners work together to keep flows across the interties within these limits. Intertie flows are also managed by the IESO to ensure the stable operation of the electricity grid within Ontario.

Types of Interjurisdictional Energy Trading



There are three types of interjurisdictional energy transactions. A participant can:

- import energy or operating reserve from another control area into Ontario
- export energy from Ontario to another control area
- move energy from one jurisdiction, through Ontario, to a different jurisdiction (called “wheeling”)

In order for an intertie transaction scheduled in Ontario to flow, there must be a matching transaction scheduled in the neighbouring jurisdiction. For example, an import from New York scheduled in the Ontario market must having a matching export scheduled in the New York market. It is the responsibility of the market participant to ensure that appropriate matching transactions are scheduled by meeting the requirements of the neighbouring jurisdiction.

Import

An import involves moving energy from another control area into Ontario for use by consumers within Ontario. An import acts much like an internal generator in that it helps meet Ontario energy demand. As with internal generators, a participant wishing to complete an import transaction must make a supply offer in the IESO-administered market. Import offers are considered along with all other offers received from suppliers. An import offer is accepted and scheduled if:

- it is required to meet demand,
- it is economic in comparison to other supply, and
- it can be physically accommodated by the intertie and the IESO-controlled grid.

Export

Exports are treated in much the same way as internal dispatchable load. In order to export energy, a participant must place a bid in the IESO-administered market to purchase energy at the intertie. An export will be scheduled if the bid is economic and the intertie and IESO-controlled grid can physically accommodate the transaction.

Wheel-Through

A wheel-through allows a participant to move energy from one jurisdiction through Ontario to another jurisdiction. For example, a participant may want to move energy from New York to Minnesota through Ontario. This movement is achieved bytransacting both an import to Ontario and an export from Ontario during the same period.

In the simplest form of wheel-through, a participant makes an offer to import energy and a bid to export energy during the same period. If both the bid and offer are accepted, the energy will flow into and out of Ontario at the same time. Importantly, in this form of wheel-through the two transactions (import and export) are totally independent from each other. The success of one

transaction has no influence on the success of the other. Therefore, if one leg fails, the other may still flow. This may present a risk to the participant.

This risk can be avoided by "linking" the two legs of the wheel-through. This ensures that if one leg of a wheel-through is curtailed or fails, the other leg will also be curtailed.

Linking a wheel-through is achieved by:

- Offering the import leg of the transaction at between -$50 and negative maximum market clearing price (i.e., -$2,000)
- Bidding the export leg at maximum market clearing price (i.e., $2,000)
- Submitting the NERC tags for each leg in a particular format (see the section "Placing Bids and Offers" below)[1]

Operating Reserve

Operating reserve is stand-by power or demand reduction that the IESO must have available in case of a contingency on the grid such as the loss of a generator. If a contingency occurs, operating reserve is activated, re-establishing the balance between supply and demand and thereby maintaining system reliability. The IESO purchases operating reserve on behalf of the market. The cost is then charged back to loads (including exports) through an uplift.

Market participants involved in imports and exports can offer 10 minute non-spinning and 30 minute operating reserve. In order to offer operating reserve you must:

- be able to provide the energy when called upon within the time frame specified by the class of operating reserve involved (either 10 minutes or 30 minutes)
- be able to supply the energy for up to one hour (the neighbouring jurisdiction must allow this to occur)
- have a bid or offer in the energy market for an amount greater than or equal to the quantity of your operating reserve offer

[1] Please see *Market Manual 4.2: Submission of Dispatch Data In the Real-time Energy and Operating Reserve Markets* on the Rules, Manuals and Forms web pages for more details on wheel-throughs

3. Placing Bids and Offers

Placing an offer or bid at an intertie is very similar to placing one within Ontario:

- Bids and offers are placed using the Energy Market Graphical User Interface Workspace.[2]
- Scheduling is independent of any bilateral contracts. All transactions must clear the market economically. No preference is given to those covered under contractual agreements.
- No physical transmission rights are required. Once a transaction is scheduled, the participant has access to Ontario's transmission system.

There are two primary differences, however, between bids and offers within Ontario and those at the interties:

- A participant bidding or offering in Ontario has to indicate the location of the desired transaction (i.e., where the energy will either be injected into or taken out of the IESO-controlled grid). This information is required by the IESO computer algorithm so that it can evaluate the effects of any physical system constraints when considering the transaction. Knowing the location of the transaction is also critical information for settlement purposes. Participants indicate their transaction's location by entering a resource name with their bid or offer. A resource name is a unique identifying reference which is associated with a facility (e.g., a generator or load).
- With intertie transactions, the IESO needs to know where the energy is going to (if an export) or coming from (if an import). However, intertie bids and offers are not associated with a facility registered within Ontario. Therefore, a boundary entity resource is used to indicate an intertie transaction's location.[3] In addition to the resource, the participant must also indicate which intertie they plan to use.

[2] Please see the *Energy Market Graphical User Interface Workspace Training Manual* available on the Training home page for more information on entering, revising and cancelling offers and bids.

[3] Please see *Market Manual 4.2: Submission of Dispatch Data in the Real-time Energy and Operating Reserve Markets* on the Rules, Manuals and Forms web pages for a complete listing of boundary entity resources.

- The market participant must enter a NERC tag with their export bid or import offer.[4] Participants are responsible for updating the tag if the quantity of energy that clears the market is different from the quantity indicated in the originally submitted NERC tag (see the next section for timing).[5] The Ontario portion of the transaction should be designated as FIRM "7F". Quebec transactions should use the control area HQT. If entering a linked wheel-through:
  - The import leg tag should be in the format:

    WI_Source Control Area Sink Control Area
  - The export leg tag should be in the format:

    WX_Source Control Area Sink Control Area

Scheduling Interjurisdictional Trade

The IESO uses a computer algorithm called the Dispatch Scheduling Optimizer (DSO) to determine prices and schedules.[6] It is run in two timeframes:

- Hourly in "pre-dispatch" to determine projected prices, projected schedules for dispatchable facilities within Ontario, and projected and actual interchange schedules
- Every five minutes in "real-time" to determine actual dispatch schedules for facilities within Ontario, and settlement prices

Participants with dispatchable facilities in Ontario receive dispatch instructions every five minutes. Dispatch instructions tell the participant what quantity of energy they should be injecting or withdrawing by the end of the five-minute interval during which the instruction was received.

The IESO cannot issue dispatch instructions every five minutes in real-time to facilities located outside of Ontario. Instead, interjurisdictional trade is co-ordinated between the IESO and other balancing authorities, using hourly interchange schedules. Imports and exports are scheduled on an economic basis within the physical security limits of the intertie and of the IESO-controlled grid. Which imports or exports are accepted for a particular dispatch hour is determined by the pre-dispatch run of the DSO during the preceding hour (for example, the schedule for noon to 1:00 p.m. is determined between 11:00 a.m. and noon). This schedule is then confirmed with our neighbouring jurisdictions to determine if matching transactions have been scheduled. Once this is confirmed, transactions become fixed for the dispatch hour. This means that they do not change during the hour (unless a change is needed for reliability reasons). Further, no additional intertie transactions can be made to flow during the hour using market mechanisms.

[4] NERC (North American Electric Reliability Council) tags are participant-selected codes that identify intertie transactions. For more information on NERC Tags, please see the NERC web site: www.NERC.com and Market Manual 4.2, *Submission of Dispatch Data in the Real-Time Energy and Operating Reserve Markets* available on the IESO Rules, Manuals and Forms web page.

[5] Except for transactions with New York, where the sink balancing authority will make any required changes for you. Please see *Market Manual 4.2: Submission of Dispatch Data in the Real-time Energy and Operating Reserve Markets* on the Rules, Manuals and Forms web pages

[6] See the *Introduction to Ontario's Physical Markets* workbook available on the Training web pages

Therefore, intertie transactions compete economically in pre-dispatch in order to be scheduled, but are then fixed for the hour in real-time. This has an important effect on pricing and settlements, which will be explained in later sections.

Participants use the IESO Reports site to retrieve their interchange schedules before the dispatch hour. For example, the interchange schedule for the hour starting at 9:00 a.m. eastern standard time (EST) is determined by a run of the IESO algorithm starting at 8:07 a.m. This interchange schedule should be available by 8:20 a.m. Participants are required to supply valid NERC tags at least 30 minutes prior to the dispatch hour (35 minutes if Transmission Load Relief has been declared).

Summary

Market participants who wish to import energy must make an offer to inject into the IESO-controlled grid. An import offer is placed using the Energy Market Graphical User Interface in much the same way as a generator in Ontario places an offer.

Market participants who wish to export energy must make a bid to withdraw energy from the IESO-controlled grid. An energy bid is placed using the Energy Market Graphical User Interface in much the same way as a dispatchable load in Ontario places a bid.

Import offers and export bids are evaluated by the DSO algorithm, taking into consideration both the economic competitiveness of the bid or offer, and the physical ability of the intertie and of the IESO-controlled grid to accommodate the transaction.

Interjurisdictional transactions are scheduled by the last pre-dispatch run of the algorithm before the dispatch hour. They are then fixed for the dispatch hour at the quantity determined hour ahead.

Skill Check

1. List the five adjacent control areas.
   a.
   b.
   c.
   d.
   e.
2. Importers and exporters may provide operating reserve in which two classes?
   a.
   b.
3. True or False:
   a. If the IESO accepts an import offer and schedules the import, the participant is guaranteed access to the intertie, the IESO-controlled grid, and to facilities in neighbouring control areas.
4. In order to ensure a successful wheel-through, the market participant must:
   a. Make a successful offer to import and a successful bid to export
   b. Link the export and import legs
   c. Successfully navigate the affected neighbouring jurisdictions
   d. a) and c)
   e. a), b) and c)
5. Select the 2 correct statements:
   a. Imports and exports are scheduled for 5-minute blocks
   b. Interchange schedules are for 1-hour time periods
   c. Having a physical bilateral contract guarantees that your transaction will be scheduled
   d. If the IESO cuts one leg of a non-linked wheel-through, it will not automatically cut the other leg

Skill Check: Answers

1. List the five intertie points with adjacent control areas.
   a. **Manitoba**
   b. **Minnesota**
   c. **Michigan**
   d. **New York**
   e. **Quebec**
2. Importers and exporters may provide operating reserve in which two classes?
   a. **10 minute non-spinning**
   b. **30 minute**
3. True or False:
   a. If the IESO accepts an import offer and schedules the import, the participant is guaranteed access to the intertie, the IESO-controlled grid, and to facilities in neighbouring control areas: **FALSE**

Comment: The participant must still navigate the neighbouring jurisdiction and ensure their NERC tags are valid.

4. In order to ensure a successful wheel-through, the market participant must:
   a. Make a successful offer to import and a successful bid to export
   b. Link the export and import legs
   c. Successfully navigate the affected neighbouring jurisdictions
   d. **Answer**: a) and c)
   e. a), b) and c)

Comment: The likelihood of a wheel-through being successfully scheduled is not increased by linking the two legs. Doing so only ensures that if one leg fails, the other will be cut.

5. Select the two correct statements:
   a. Imports and exports are scheduled for 5-minute blocks.
   b. **Correct**: Interchange schedules are for 1-hour time periods
   c. Having a physical bilateral contract guarantees that your transaction will be scheduled
   d. **Correct**: If the IESO cuts one leg of a non-linked wheel-through, it will not automatically cut the other leg

4. Pricing and Scheduling of Interjurisdictional Trade

Imports are paid the price in the zone through which they are importing while exports pay the price in the zone through which they are exporting. Intertie zone prices may be higher, lower, or the same as the price used to settle transactions occurring in the Ontario zone. Differences between the Ontario and intertie zone prices are caused by congestion.

When you have completed this chapter, you will be able to:

- Define “intertie congestion price” (ICP)
- Given a set of bids and offers, determine the Ontario market clearing price (MCP) and an intertie zone price in a situation with congestion and in a situation without congestion
- Explain the impact on settlements of scheduling imports and exports an hour ahead

Prices and Constraints

As discussed in Section 2, the IESO uses the Dispatch Scheduling Optimizer (DSO) algorithm to determine prices and schedules. It is run in two time frames:

- Hourly in “pre-dispatch” to determine projected prices, projected schedules for dispatchable facilities within Ontario, and projected and actual interchange schedules
- Every five minutes in “real-time” to determine actual dispatch schedules for facilities within Ontario, and settlement prices

The DSO is run in both an unconstrained and constrained mode in both the pre-dispatch and real-time timeframes:

- The unconstrained mode determines prices and market schedules with limited reference to the physical limitations of the electricity system
- The constrained mode determines dispatch schedules taking the physical system into consideration[7]

[7] For more information on DSO modes, please see the *Introduction to Ontario’s Physical Markets* workbook, available on the Training web pages

The DSO determines prices for Ontario as well as for a number of intertie zones:

Control Area	Code(s)
Ontario	ONZN
Manitoba	MBSI
Minnesota	MNSI
Michigan	MISI
New York	NYSI
Quebec	PQBE
	PQDA
	PQDZ
	PQHA
	PQHZ
	PQPC
	PQQC
	PQXY
	PQAT

Imports are paid the price in the intertie zone while exports pay the price in the zone. Intertie zone prices can be higher, lower, or the same as the price used to settle transactions occurring in the Ontario zone. Differences between the Ontario and intertie zone prices are caused by congestion. But what is congestion in this context? As with any transmission line, the interties that connect Ontario to neighbouring control areas have a maximum allowable flow limit. Scheduling transactions in excess of this limit can result in reliability issues, such as overheating. A maximum flow limit can be referred to as a “constraint” as it constrains the ability of the DSO to schedule transactions. Because of these flow limits, there can be more energy trying to move in a given direction across an intertie than can be physically accommodated. When this occurs, the DSO may not beable to schedule all of the transactions that have an economic bid or offer. Instead, because energy can only be scheduled up

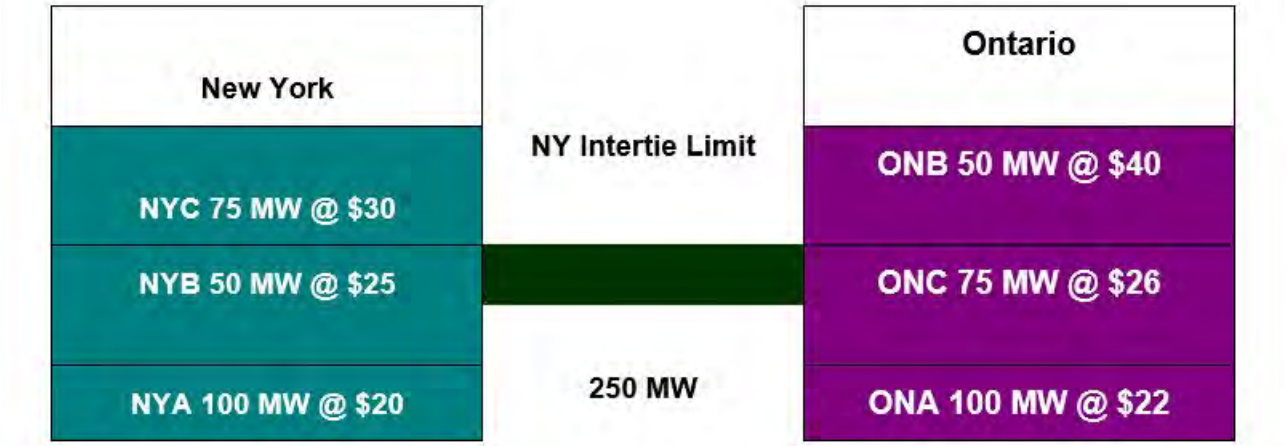
to the maximum flow limit, energy that is otherwise economic may be left unscheduled. When this occurs the “constraint” is said to be “binding” due to congestion.

A binding intertie constraint impacts both scheduling (by the constrained mode of the DSO) and pricing (by the unconstrained mode). This is because the unconstrained mode takes into account the limitations of the interties (although it ignores transmission limitations within Ontario).

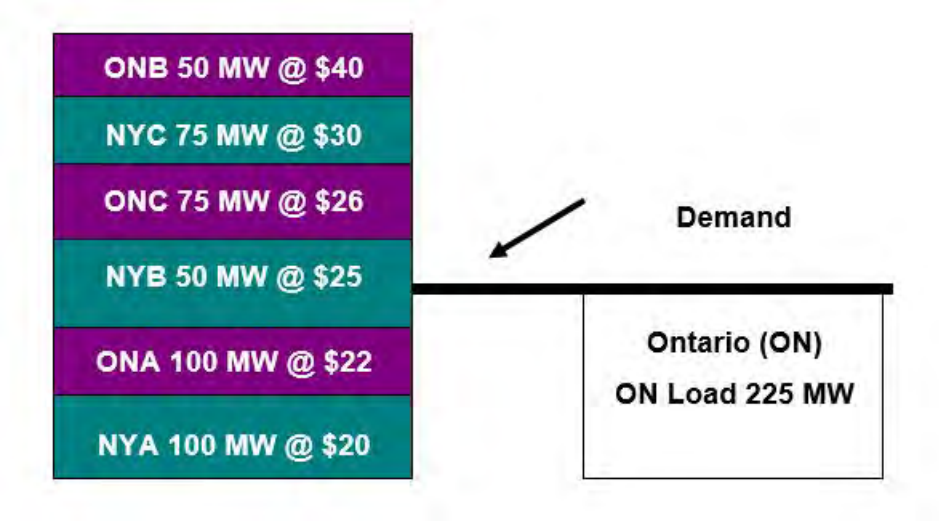
Let’s look at some simplified examples to illustrate the potential scheduling and pricing impact of intertie constraints.

Pre-Dispatch

In this example, there are three generator offers in Ontario and three import offers in the New York zone. The intertie can accommodate up to 250 megawatts (MW) of flow either into or out of Ontario. Demand in Ontario is 225 MW. There are no exports bid in the New York zone.



The DSO looks for the most economic combination of resources that can satisfy demand and that can be accommodated within the physical limitations of the system. Therefore, the pre-dispatch offer stack used by the DSO to satisfy Ontario demand includes offers from Ontario resources as well as imports. Importantly, however, imports are included only to the extent that the intertie can physically transfer the energy. In this example, the intertie can accommodate up to 250 MW of imports. Since there are only 225 MW of import offers, all of the New York import offers will be included in the pre-dispatch offer stack and considered for scheduling. This is illustrated below:



Given Ontario demand of 225 MW, the Ontario zone price would be set by an offer from the NY intertie (NYB) of $25. The resulting Market (unconstrained) schedules would be:

- NYA: 100 MW
- ONA: 100 MW
- NYB: 25 MW

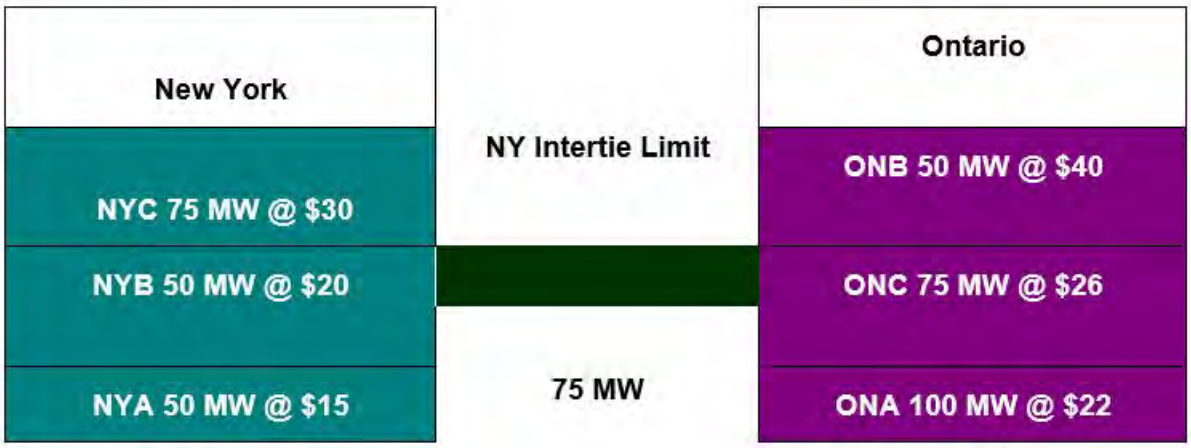
What is the price in the New York intertie zone? Price in an intertie zone is determined by calculating the cost of satisfying one additional megawatt (MW) of non-dispatchable demand in that zone.

In the above example, what was the demand in the NY zone before the application of this additional MW? It was the total energy scheduled for import to Ontario, or 125 MW. Given this, what would the cost be to satisfy one additional MW of non-dispatchable demand in the NY zone? In this case, the most economical method would be to use

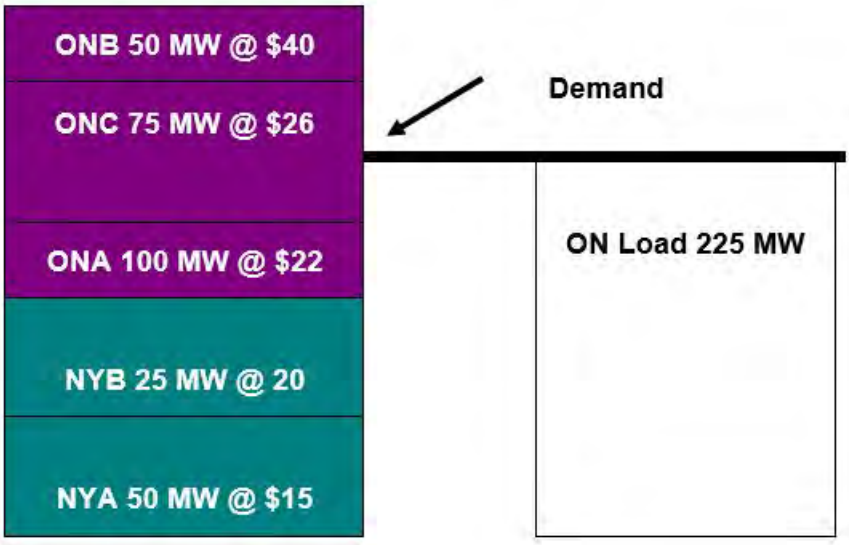
NYB's offer at $25. Therefore, the price in the intertie zone and the price in the Ontario zone are the same, indicating a lack of congestion (i.e., there is no binding constraint affecting price).

What happens if a constraint is binding? Intertie congestion is said to occur when the physical limitations of the intertie restrict the movement of otherwise economic energy to and/or from another control area. When intertie congestion occurs, transactions that might otherwise have been accepted cannot be scheduled. The unconstrained mode of the algorithm, which is used for price setting, includes the physical limitations of the interties. Therefore, intertie congestion has a price impact.

We can see the impact of this congestion on both intertie and Ontario zone prices by revisiting our previous example. All of the offers are the same and Ontario demand remains at 225 MW. This time, however, the intertie limit is only 75 MW.



In this example, the unconstrained mode of the algorithm can only consider the most economic 75 MW from the New York zone (which will come from NYA's offer of 50 MW at $15 and NYB's offer of 50MW at $20) when setting the Ontario price. The resulting offer stack is shown below. With this offer stack, ONC becomes the marginal (i.e., price- setting) unit. The Ontario zone price becomes $26 instead of the $25 set by NYB in the previous example:



The resulting Market (unconstrained) schedules in this scenario would be:

- NYA: 50 MW
- NYB: 25 MW
- ONA: 100 MW
- ONC: 50 MW

What is the price in the New York zone? Remember that this price is set based on the cost of satisfying one additional MW of non-dispatchable demand in the intertie zone. In this case, how can we best satisfy a 76th MW of demand?

NYA offered 50 MW at $25 and NYB offered 50 MW at $20 only 75 MW of which could be included in the Ontario stack. This offer is the most economical way to satisfy NY zonal demand. Therefore, the price in the NY zone would be $20. The price in the NewYork zone was lower than the Ontario zone price of $26 because the intertie could not physically transfer all of the energy that was economic from the NY zone into Ontario. This means that the intertie was “import-congested”. Conversely, an intertie is “export congested” if there are more economic export bids than can be accommodated by the intertie. When this happens, the price in the intertie zone is higher than the Ontario zone price.

The difference between the Ontario zone price and the intertie zone price reflects the cost of congestion on that interface. For example, if the intertie zone price was $50 and the Ontario zone price was only $20, the cost of congestion was $30.

Real-Time

“Real-time” refers to the actual dispatch period during which energy is flowing. In real- time, the MW quantity of scheduled imports and exports are fixed for the hour based on the transactions selected in pre-dispatch. This means that even if real-time demand or price is different than anticipated in pre-dispatch, the schedule for intertie transactions cannot change during the hour.[8] For example, assume that only 50 MW of a 100 MW import offer was scheduled. Even if conditions in real-time meant that the full offer would be economic, no additional energy can be scheduled. Similarly, the import can't be reduced, even if the price in real-time falls below its offer price. Further, offers or bids that weren’t selected in pre-dispatch can’t be allowed to flow during the dispatch hour even if they would have now been economic.

The quantity of transactions scheduled in pre-dispatch to run in real-time is limited by the transfer limits of the interties. In other words, the total scheduled to flow in real-time can be no greater than the intertie’s maximum capacity. Because the schedule can’t exceed the maximum flow limit, there can be no congestion on the interties in real-time to cause price differences between intertie zones and the Ontario zone. However, as seen above, there may have been congestion-caused price differences in pre-dispatch. If real- time prices don’t respect the cost of this congestion, settlements may be inappropriate.

So how are real-time prices determined for imports and exports that respect the impacts of congestion? This is done this by adding an “intertie congestion price” (ICP) to each of the 5-minute real-time prices in Ontario during the dispatch hour. The ICP reflects the difference between the intertie zone price and the Ontario zone price as determined in pre-dispatch:

[8] Except in limited circumstances for reliability reasons. See *Market Manual 7.4, IMO-Controlled Grid Operating Policies,* available on the IESO Rules, Manuals and Forms web page.

Intertie Congestion price (ICP) = Pre-dispatch Intertie Zone Price - Pre-dispatch Ontario Price

For example, if we have a price in the Ontario zone of $24 and a price in the NY intertie zone of $25 in the hour prior to dispatch, the ICP would be:

ICP = $25 - $24 = $1

The price used to settle imports and exports, therefore, is a combination of the real-time five-minute market clearing price (MCP) in Ontario and the pre-dispatch ICP.[9]

Real-Time Intertie Zone Price = Ontario MCP + ICP

If the real-time price in Ontario is the same as the last pre-dispatch projected price for that hour, by adding the ICP, the intertie zone settlement price will equal the pre- dispatch intertie zone price. Continuing our example from above, if the real-time Ontario price comes in at $24 (as projected in pre-dispatch), adding the $1 ICP to it will result in an intertie settlement price of $25 (which was the pre-dispatch projected price in the NY intertie zone):

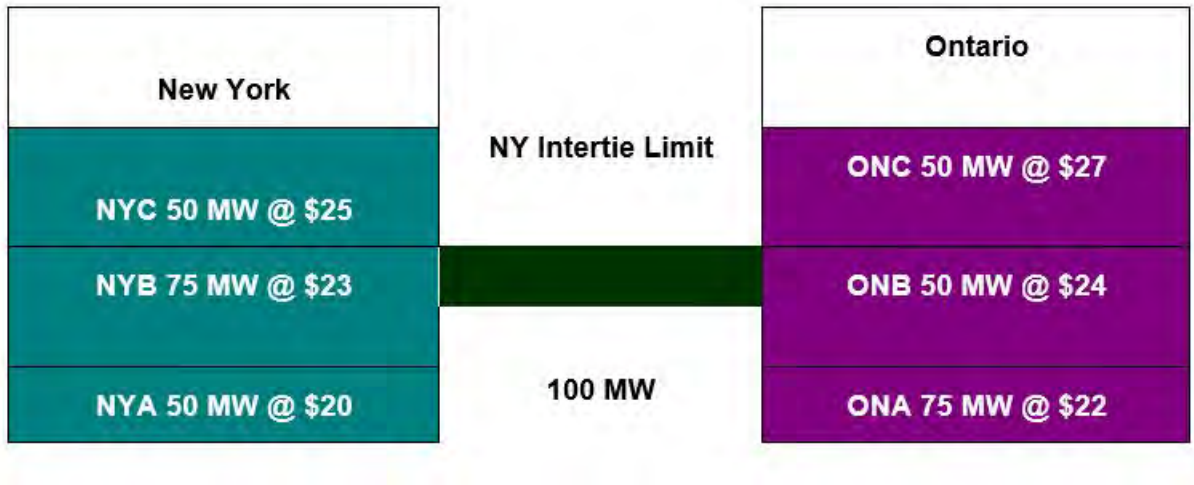
Real-Time NY Intertie Zone Price = Ontario MCP + ICP

Real-Time NY Intertie Zone Price = $24 + $1

Real-Time NY Intertie Zone Price = $25

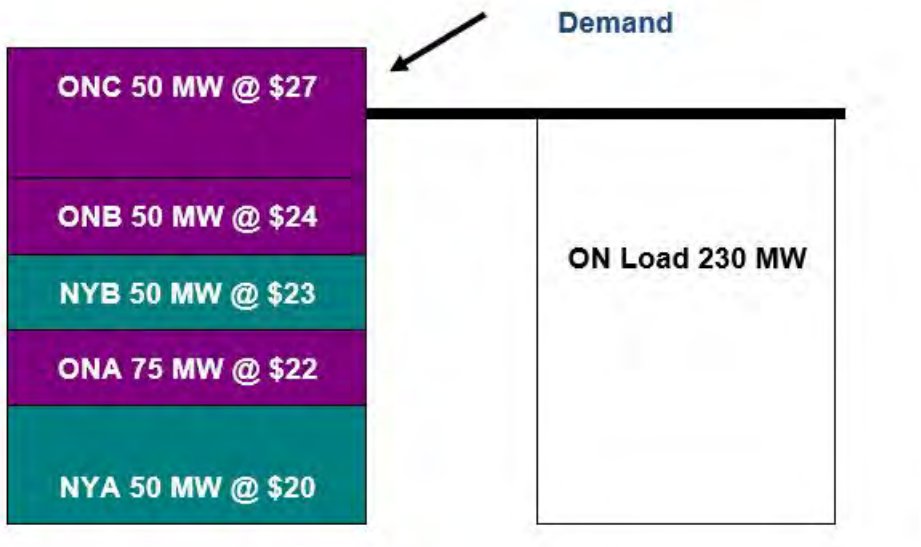
This method of setting real-time intertie zone settlement prices presents a price risk for those conducting intertie transactions because the Ontario MCP in real-time can be different than the pre-dispatch projection of price. The following example illustrates the risk:

Here we have three offers in the NY zone and three offers in the Ontario zone. Demand in Ontario is 230 MW and the intertie has a capacity of 100 MW:



[9] Note: This may not be the case where prices are administered. As well, prices cannot exceed the maximum market clearing price.

In pre-dispatch, the offer stack would look like this:



Remember that NYC cannot be considered even though its offer price is lower than ONC's because the intertie can transfer only 100 MW. NYA and NYB have lower offer prices than NYC, so are considered first. Given this stack, the price in Ontario would be $27.

What would the price in the NY zone be? Remember that the price in the intertie zone is set based on the cost of satisfying one additional MW of non-dispatchable demand in that zone. NYB offered 75 MW at $23. Only 50 MW could be taken across the intertie, however. Therefore, NYB still has 25 MW of energy available at $23. Therefore, the price in the NY zone would be $23.

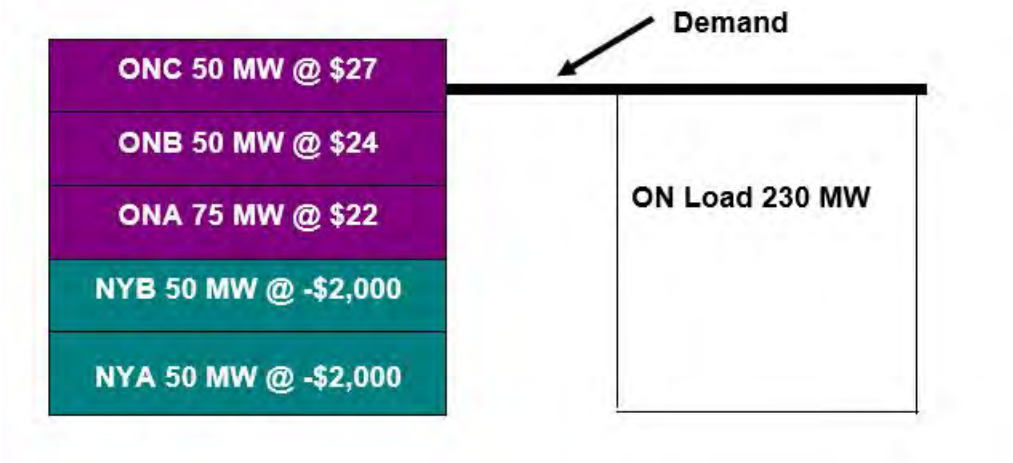
Given a $23 NY zone price and an Ontario zone price of $27, the intertie congestion price would be:

ICP = Pre-dispatch Intertie Zone Price - Pre-dispatch Ontario Price

= $23 - $27 = - $4

In real time, the DSO treats imports and exports as non-dispatchable resources, as their quantity cannot be changed. It does this by assuming that all scheduled imports were offered at negative maximum market clearing price (-$2,000) and that all scheduled exports were bid at positive maximum market clearing price ($2,000). In other words, it assumes that imports and exports are willing to pay up to $2,000/MW (the maximum price in the market) for the ability to flow.

In our example then, the DSO assumes that the scheduled offers from the NY intertie were offered at negative $2,000. Given this, if demand is unchanged at 230 MW, the Ontario MCP would remain at the pre-dispatch value of $27, as illustrated below:



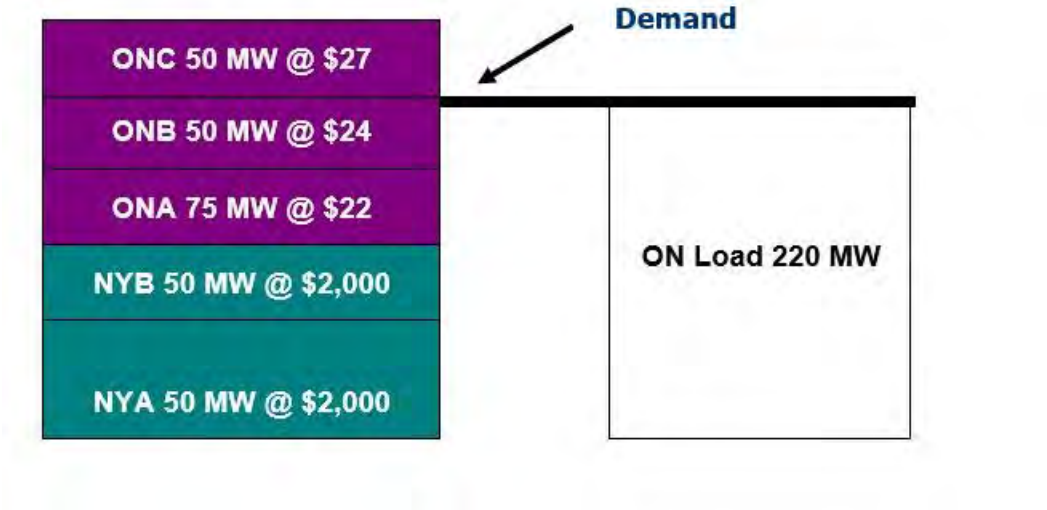
Therefore, the real-time intertie zone price would be:

Real-Time Intertie Zone Price = Ontario MCP + ICP

= $27 + (-$4) = $23

This is the same price as was projected in pre-dispatch. Therefore, both NYA and NYB achieve in real-time the operating profit they anticipated achieving in pre-dispatch. (Operating profit is the difference between a participant's offer price and the intertie zone price. See page 25 for more information on operating profit.)

However, the real-time Ontario MCP can be different from the pre-dispatch projection. This can occur, for example, if demand in real-time is different than what was projected in pre-dispatch. Let's assume that the real-time demand in our example is 220 MW instead of the 230 MW projected in pre-dispatch.



If this were to occur, the Ontario zone price in real-time would be $24. This would mean a real-time settlement price in the intertie zone as follows:

Real-Time Intertie Zone Price = Ontario MCP + ICP

= $24 + (-$4) = $20

This is $3 lower than the intertie zone price of $23 that was projected in pre-dispatch. Further, this price is below the $23 offer price of NYB. There is a price risk, then, for participant's transacting at the interties caused by the fact that transactions are scheduled based on pre-dispatch projections but are settled based on real-time prices. We will discuss how this price risk is mitigated for importers in *Section 5: Intertie Offer Guarantee.*

Summary

When there is no congestion, the MCP (market clearing price) for an intertie zone will be the same as the Ontario zone MCP. If there is import congestion the price in the intertie zone will be lower than the price in the Ontario zone. If there is export congestion, the intertie zone price will be higher than the Ontario zone MCP.

Imports and exports are scheduled based on the pre-dispatch results during the hour prior to the actual dispatch hour. The price used to settle the transaction is a combination of the intertie congestion price (ICP) from pre-dispatch, and the twelve 5- minute real-time Ontario prices during the dispatch hour.

Skill Check

1. True or False:
   a. A binding constraint is one that limits the ability of the DSO to schedule all energy that is economic.
2. Given a $30 NY zone price and an Ontario zone price of $24, the intertie congestion price would be:
   a. $6
   b. $3
   c. -$6
3. True or False:
   a. The physical limitations of the interties have no impact on the price in Ontario.
4. Select the 2 correct statements:
   a. Imports and exports can be adjusted for economics during a dispatch hour
   b. In real-time, the DSO assumes that all scheduled imports were offered at negative maximum market clearing price (-$2,000) and that all scheduled exports were bid at positive maximum market clearing price ($2,000)
   c. The price in an intertie zone is set based on the cost of satisfying one more MW of demand in the zone.
   d. If there is intertie congestion, the price in the intertie zone will be the same as the Ontario price
5. What is the price in the Michigan zone and the price in Ontario, given Ontario demand of 350 MW, a Michigan intertie capacity of 150 MW, and the following offers:

Michigan Import Offers	Ontario Offers
MIA 100 MW at $25	ONA 150 MW at $37
MIB 75 MW $35	ONB 100 MW at $45
MIC 50 MW at $40	ONC 100 MW at $50

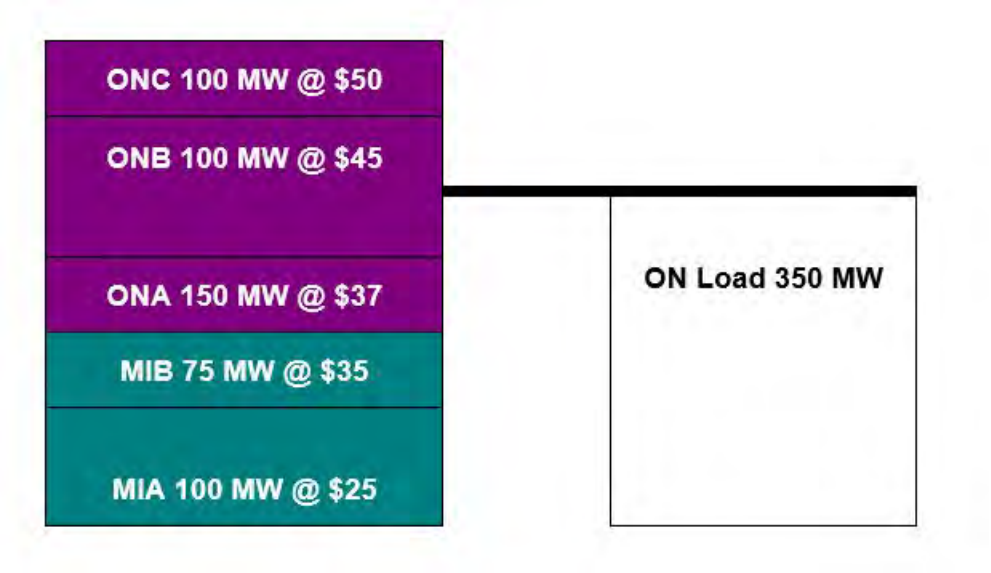
Skill Check: Answers

1. True or False:
   a. A binding constraint is one that limits the ability of the DSO to schedule all energy that is economic: **TRUE**
2. Given a $30 NY zone price and an Ontario zone price of $24, the intertie congestion price would be:
   a. **Answer**: $6
   b. $3
   c. -$6
3. True or False:
   a. The physical limitations of the interties have no impact on the price in Ontario: **FALSE**
4. Select the 2 correct statements:
   a. Imports and exports can be adjusted for economics during a dispatch hour
   b. **Answer 1**:In real-time, the DSO assumes that all scheduled imports were offered at negative maximum market clearing price (-$2,000) and that all scheduled exports were bid at positive maximum market clearing price ($2,000)
   c. **Answer 2**: The price in an intertie zone is set based on the cost of satisfying one more MW of non-dispatchable demand in the zone
   d. If there is intertie congestion, the price in the intertie zone will be the same as the Ontario price
5. What is the price in the Michigan zone and the price in Ontario, given Ontario demand of 350 MW, a Michigan intertie capacity of 150 MW, and the following offers:

Michigan Import Offers	Ontario Offers
MIA 100 MW at $25	ONA 150 MW at $37
MIB 75 MW $35	ONB 100 MW at $45
MIC 50 MW at $40	ONC 100 MW at $50

See next page for answer:

Ontario offer stack



MIC would not be included in the stack as the intertie can only take 150 MW. Therefore, the price in Ontario is $45.

The price in Michigan would be $35 as set by MIB.

5. Congestion Management and Interjurisdictional Trade

Market schedules and prices are determined by the unconstrained mode of the DSO whereas dispatch (interchange) schedules are determined using a constrained mode. Because these two modes consider different factors, there can be a difference between a participant's market schedule and their interchange schedule. Such a difference can result in a change in operating profit. If this occurs, congestion management settlement credits (CMSC) return the participant to their market schedule operating profit.

Chapter 9 of the market rules, *Settlements and Billing*, outlines the use of CMSC. The

Introduction to Ontario's Physical Markets workbook explains CMSC as it is generally applied in the IESO-administered markets. In this section we will discuss how CMSC specifically relates to imports and exports.

Objectives

After completing this section you will be able to:

- Explain the differences between the market schedule and the interchange schedule
- Calculate operating profit
- Calculate CMSC for imports and exports

Schedules, Dispatch Instructions, and Interchange Schedules

As discussed in the *Introduction to Ontario's Physical Markets*, the unconstrained mode of the algorithm determines prices and market schedules while the constrained mode determines dispatch schedules. The table below summarizes the different inputs used by these two modes:

Unconstrained Algorithm Inputs	Constrained Algorithm Inputs
• Flow limitations on interties • Hourly facility ramp rates based on MP input (energy market only) • Last scheduled point for the facility	• Flow limitations on interties • Limitations on the IESO-controlled grid • Limitations provided by the MP, including actual ramp rates • Last actual operating point

While there are a number of circumstances under which a participant's market (unconstrained) and dispatch (constrained) schedules will be different, congestion on an intertie itself is not one of them.

Constraints on the intertie are considered in both the unconstrained and constrained mode of the DSO. Therefore, both modes are affected to the same degree by intertie congestion. For intertie transactions, the most common reason for CMSC is congestion on the IESO-controlled grid that restricts the ability of the grid to accommodate the transaction. Consistent with the limit on the settlement price for export transactions the amount of CMSC paid to both constrained on and constrained off exports is limited to result in the same resultant CMSC consistent with what the transaction is settled at.

Please note that linked wheel-through transactions are not eligible for CMSC.

CMSC and Operating Profit

If a participant's dispatch schedule is different from their market schedule, their operating profit may be affected. Operating profit for an importer is the difference between the revenue received for the energy sold and the cost of supplying the energy, as represented by their offer price. For an exporter, operating profit is the difference between the cost of purchasing the energy, and the benefit they realize by using the energy, as represented by their bid price (see *Introduction to Ontario's Physical Markets*). Therefore:

- For imports: Operating Profit = (MCP – Offer Price) x Quantity
- For exports: Operating Profit = (Bid Price – MCP) x Quantity

MCP for intertie transactions is the market clearing price in the intertie zone.

CMSC returns a participant to their market schedule operating profit when their market and dispatch schedules are different. This is done because the market rules reflect the principle that no participant should be unduly benefited or harmed because of their physical location in relation to the transmission grid. The general formula for CMSC is:

CMSC = Operating Profit (Market Schedule) – Operating Profit (Dispatch Schedule)

We can illustrate the calculation of CMSC payments with an example:

Transbord offers to import 100 MW into Ontario if the price is $22 or higher. The pre- dispatch price in Ontario is $25. As there is no congestion on the intertie, the pre- dispatch intertie zone price in this example is also $25. Therefore, ICP = $25 - $25 = $0.

Transbord's market (unconstrained) schedule would be the full 100 MW offered because their offer price is less than the intertie zone price and there is no intertie congestion.

In this example, let's assume that there is a system constraint on the IESO-controlled grid that prevents the constrained mode from accepting any of the energy from Transbord. Therefore, Transbord's dispatch schedule is 0 MW. (Remember that the unconstrained mode does not recognize constraints *within* Ontario so the market schedule was not impacted by the constraint.)

Let's further assume that the Ontario zone MCP in real-time comes in at $25 for all intervals. ICP was $0, so the real-time intertie zone MCP is also $25. Given this, Transbord's market schedule operating profit would be:

Market Schedule OP = (MCP – Offer Price) x Market Schedule Quantity

= ($25 – $22) X 100 MW

= $300

However, their dispatch schedule operating profit would be:

Dispatch Schedule OP = (MCP – Offer Price) x Dispatch Schedule Quantity

= ($25 – $22) X 0 MW

= $0

Therefore, instead of a $300 operating profit, as per the market schedule, Transbord now stands to receive a $0 operating profit because of a system constraint that was beyond their control.

The market rules were designed so that no participant unduly suffers or benefits by their location relative to the IESO-controlled grid. The participant's constrained schedule was different from their unconstrained schedule because of a constraint on the IESO- controlled grid. Therefore, Transbord would receive a CMSC payment sufficient to return them to their market schedule operating profit. This effectively compensates them for the effect of the constraint on their profitability:

CMSC = Operating Profit Unconstrained – Operating Profit Constrained

= $300 - $0

= $300

Negative CMSC Payments

Congestion management settlement credits are intended to restore participants to the operating profit they would have had under their market schedule. While this is normally a payment, there are circumstances under which CMSC is a debit. This occurs if the participant's dispatch schedule leads to a higher operating profit than they would have received under their market schedule. In these cases, a CMSC payment *from* the participant is required in order to restore their operating profit to their market schedule level. This type of situation can occur with intertie transactions because of the timing of the scheduling process. An example will illustrate:

In pre-dispatch, Exbord places a bid to export 120 MW at the New York intertie zone if the price is $30 or less. In pre-dispatch, the New York zone price is determined to be $28, the same as the Ontario price. Therefore, the ICP for the New York intertie zone is zero. In this scenario, Exbord would receive a market schedule for all 120 MW.

Assume that a system constraint inside Ontario prevents this transaction from being scheduled by the constrained mode. Exbord's dispatch schedule would be 0 MW.

Assume that in real-time the average price over the hour in both the Ontario and New York zones is $42.50 (ICP = $0). This is substantially higher than Exbord's export bid of

$30. Because their dispatch schedule was 0 MW, Exbord is not flowing in real-time. However, Exbord did receive a market schedule. Therefore, we have to determine their real-time market schedule operating profit and compare it to their real-time dispatch schedule operating profit (which is $0 because they are not flowing).

The table below shows the twelve 5-minute real-time prices for Ontario and for the New York zone, as well as the market schedule operating profit for Exbord for each interval:

Market Schedule – Real-time

Interval	Ontario MCP $	New York Zone Price $	Offer $	Operating Profit $/MWh	Energy MWh[10]	Total Operating Profit $
1	26	26	30	4	10	40
2	26	26	30	4	10	40
3	29	29	30	1	10	10
4	29	29	30	1	10	10

[10] The offer was for 120 MW for one hour. This translates to an energy quantity of 120 MWh in one hour. Dividing by 12 intervals means 10 MWh per interval.

5	50	50	30	-20	10	-200
6	50	50	30	-20	10	-200
7	50	50	30	-20	10	-200
8	50	50	30	-20	10	-200
9	50	50	30	-20	10	-200
10	50	50	30	-20	10	-200
11	50	50	30	-20	10	-200
12	50	50	30	-20	10	-200

In total, Exbord's market schedule would result in a negative operating profit (i.e., a loss) of $1,500. However, because they were constrained-off and not allowed to flow, Exbord avoided incurring this loss.

What does this mean for CMSC? Remember that CMSC is designed to return the participant to their market schedule operating profit. Therefore:

CMSC = Market Schedule Operating Profit – Dispatch Schedule Operating Profit

= -$1,500 - $0

= -$1,500

In this example, Exbord would be required to pay $1,500 in CMSC in order to restore it to the negative operating profit (loss) that it would have incurred had it not been constrained off.

Exbord's market schedule would have resulted in a loss because of the timing of when the transaction was scheduled. An intertie transaction is scheduled during the hour before the actual dispatch hour based on pre-dispatch prices. It is settled, however, based on real-time prices. In this example, the average price in real-time was $42.50, whereas the pre-dispatch price was $28. Exbord's bid was $30. If they had not been constrained off in pre-dispatch, Exbord would have been scheduled to flow in real-time. They would have then been fixed for the hour, and unable to respond to the higher price in real-time. Therefore, because of the price difference between pre-dispatch and real- time, Exbord would have lost money had they not been constrained off.

Without a CMSC adjustment to return Exbord to their negative market schedule operating profit, they would not incur the loss they should have incurred. CMSC is used to ensure that participants are not unduly harmed *or benefited* by their location on the grid. Avoiding an operating profit loss because of

a constraint is a benefit. CMSC is most often a payment to a participant. However, in some cases, as in this example, CMSC can be a charge to the participant.

(For additional information on negative CMSC payments, please see the topic “IOG and Negative CMSC” in *Section 5: The Intertie Offer Guarantee.*)

Skill Check

1. Which of the following statements is false:
   a. The market schedule is determined by the unconstrained mode of the algorithm
   b. The dispatch schedule is determined by the constrained mode of the algorithm
   c. The unconstrained algorithm ignores flow limitations on the interties
   d. The constrained mode of the algorithm includes flow limitations on the interties
2. What would Borgpower's operating profit be if it was scheduled for 200 MW with an offer price of $45 and the price in the intertie zone was $56 for each interval:
   a. $2,200
   b. $220
   c. $26,400
   d. $2,400
3. What would the CMSC payment be, given the following:
   a. Offer 150 MW at $35
   b. Market schedule = 150 MW
   c. Dispatch schedule = 0 MW
   d. Real-time intertie zone price = $30

Skill Check: Answers

1. Which of the following statements is false:
   a. The market schedule is determined by the unconstrained mode of the algorithm
   b. The dispatch schedule is determined by the constrained mode of the algorithm
   c. **Answer**: The unconstrained algorithm ignores flow limitations on the interties
   d. The constrained mode of the algorithm includes flow limitations on the interties
2. What would Borgpower's operating profit be if it was scheduled for 200 MW with an offer price of $45 and the price in the intertie zone was $56 for each interval:
   a. **Answer**: $2,200
   b. $220
   c. $26,400
   d. $2,400
3. What would the CMSC payment be, given the following:
   a. Offer 150 MW at $35
   b. Market schedule = 150 MW
   c. Dispatch schedule = 0 MW
   d. Real-time intertie zone price = $30

Answer:

CMSC = Market Schedule Operating Profit – Dispatch Schedule Operating Profit

= ($30 - $35) X 150 MW – ($30 - $35) X 0 MW

= -$750

6. The Intertie Offer Guarantee

Import transactions are locked in for the hour based on pre-dispatch prices. However, these transactions are settled using real-time prices. As a result, those conducting imports face a settlement price risk due to the scheduling process.

A key market design principle is that the market must not adversely affect the adequacy of supply. Acting on input from stakeholders, the IESO introduced intertie offer guarantee (IOG) payments which reduce price risk for importers. These IOG payments are intended to encourage imports, helping to ensure adequate supply in Ontario.

Objectives

After completing this section you will be able to:

- Explain the purpose of the intertie offer guarantee
- Calculate an intertie offer guarantee payment
- Discuss the impact of implied wheel-throughs on the intertie offer guarantee
- Explain the relationship between negative CMSC and the intertie offer guarantee

Calculation of the Intertie Offer Guarantee

The IOG ensures that, over the course of an hour, an importer will receive revenue at least equal to their market schedule times their average offer price. By doing this, the IOG ensures that an importer does not suffer a negative operating profit over the course of an hour. In other words, they are assured that they will receive at least a $0 operating profit. The IOG is calculated as follows:

IOG = -1 X ((Intertie Zone MCP – Offer) X Market Schedule Quantity)

We can illustrate how the IOG works with some examples:

Example One

Assume Transbord offers to import 120 MW if the price is $20 or greater.

In pre-dispatch, the Ontario MCP and the intertie zone MCP are both $24 (ICP = $0). Transbord receives a market schedule for the full 120 MW.

In real-time the Ontario MCP comes in at $15 for each interval of the hour. Because the ICP is zero, the transaction is settled at an intertie zone price of $15. At this price, Transbord would have a negative operating profit:

Operating Profit = (MCP – Offer Price) X Market Schedule Quantity

= ($15 – $20) X 120 MW

= -$600

The IOG is intended to ensure that an importer does not suffer a negative operating profit over the course of an hour. In this example, therefore, the IOG would be:

IOG = -1 X ((Intertie Zone MCP – Offer) X Market Schedule Quantity)

= -1 X (($15 - $20) X 120 MW)

= -1 X (-$5 X 120 MW)

= -1 X (-$600)

= $600

The total of the energy payment ($15/MWh) and the IOG payment means that Transbord was paid its offer price of $20 for the scheduled import quantity:

Offer Price Settlement = $20 X 120 MW = $2,400

Total Settlement With IOG = $15 X 120 MW + $600 = $1,800 + $600 = $2,400

Example Two

In our previous example, the real-time price was constant during the dispatch hour. Let's look at what happens if the price fluctuates during the hour.

In this example, assume Transbord offers to import 120 MW from Michigan if the price is $20 or greater.

In pre-dispatch, the Ontario MCP and the Michigan zone price are both $24 (ICP = $0). As a result, Transbord receives a market schedule for the full 120 MW.

In real-time, the Ontario MCP (and therefore the Michigan zone MCP because ICP = $0) is:

- $28 for the first 6 intervals of the hour
- $18 for the remaining 6 intervals of the hour

In real-time, Transbord's operating profit will vary as the real-time MCP varies:

Interval	Ontario MCP $	Michigan Zone Price $	Offer $	Operating Profit $/MWh	Energy MWh[11]	Total Operating Profit $
1	28	28	20	8	10	80
2	28	28	20	8	10	80
3	28	28	20	8	10	80
4	28	28	20	8	10	80
5	28	28	20	8	10	80
6	28	28	20	8	10	80
7	18	18	20	-2	10	-20
8	18	18	20	-2	10	-20
9	18	18	20	-2	10	-20
10	18	18	20	-2	10	-20
11	18	18	20	-2	10	-20
12	18	18	20	-2	10	-20

Transbord's total operating profit over the hour would be:

($80 X 6) + (-$20 X 6)

= $480 - $120

= $360

[11] The schedule is for 120 MW for one hour. This translates to an energy quantity of 120 MWh in one hour. Dividing by 12 intervals means 10 MWh per interval.

An IOG payment is made only if an importer's total operating profit *over an hour* is negative. It is not paid to restore the operating profit for individual intervals. In this case, because the positive operating profit of the first six intervals more than compensated for the negative operating profit of the last six intervals, no IOG is payable.

Example Three

So far the examples have used offers that were for a set quantity at one price. Importers can, however, submit multiple price/quantity pairs. If they do submit more than one price/quantity pair, each pair will have its own operating profit. This can affect IOG payments.

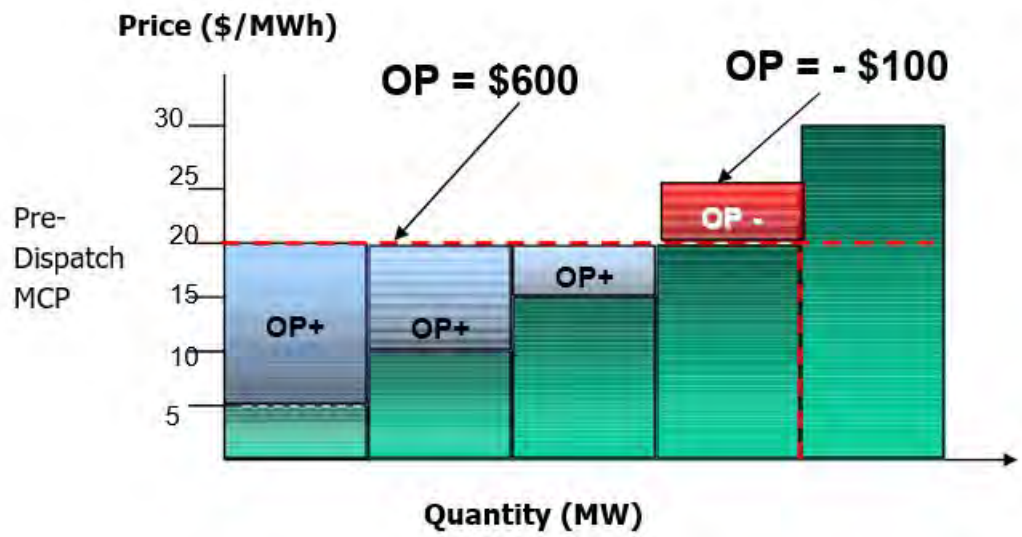
In this example, assume that Transbord makes the following offer to import from New York:

- first 20 MW at $5
- next 20 MW at $10
- next 20 MW at $15
- next 20 MW at $25
- next 20 MW at $30

In pre-dispatch, the Ontario and the New York zone prices are both $25. Transbord is scheduled for 80 MW of its 100 MW offer (the last 20 MW were offered at a price higher than the zone price).

In real-time, the actual price in both Ontario and the intertie zone is $20 for each interval. At this price, Transbord will have a positive operating profit for the first 60 MW it supplies to Ontario, but will incur a loss on the last 20 MW.

IOG with Price Lamination



Operating Profit = (MCP – Offer Price) X Quantity

= (($20 - $5) X 20 MW) + (($20 - $10) X 20 MW) + (($20 - $15) X 20 MW) + (($20 - $25) X 20 MW)

= $300 + $200 + $100 - $100

= $500

Transbord has a positive operating profit for the transaction as a whole. Again, no IOG payment will be made. Even though one price/quantity pair had a negative operating profit over the hour, the other three price/quantity pairs generated more than enough operating profit to compensate.

Wheel-Throughs

All of the above examples deal with importing power into Ontario. It is also possible to wheel energy through Ontario, that is, to have both an import and an export scheduled in the same hour. The IOG was implemented as a reliability measure to ensure that imports would be available to help Ontario meet its demand for electricity. A wheel- through of energy does not add to reliability because the increased supply represented by the import is offset by the increased demand resulting from the export. As a result, the import leg of a wheel-through is not eligible for the IOG. This applies to both linked and implied wheel-throughs (where the two legs are not formally linked – see *Section: 2 Interjurisdictional Energy Transactions*).

In order to exclude IOG payments from wheel-throughs, the IESO nets total exports against total imports in the same hour for a participant before determining if an IOG is payable. For example, assume that Transbord:

- Offers to import 120 MW from New York if the price is $20 or greater
- Bids to export 50 MW to Michigan if the price is $30 or less
- Bids to export 50 MW to Manitoba if the price is $35 or less

In pre-dispatch, the Ontario price and all intertie zone prices are determined to be $25. As a result, Transbord is scheduled for 120 MW of imports as well as 100 MW of exports. Even though the exports are not formally linked to the import, they reduce the net quantity of imports for Transbord in this hour from 120 MW to 20 MW. If an IOG becomes due, Transbord will receive payment based only on the 20 MW of imports that did not have an offsetting export.

IOG and Negative CMSC

The IOG will often work to offset a negative CMSC because the IOG is based on the market (unconstrained) rather than the dispatch (constrained) schedule. An example:

Transbord offers to import 100 MW from New York at $25. In pre-dispatch, the Ontario price is $130 and the New York zone price is $30. ICP is -$100.

Transbord is given a market schedule for all 100 MW. However, a constraint on the IESO-controlled grid prevents any of the energy from being scheduled by the constrained mode. Therefore, their dispatch schedule is 0 MW.

In real-time, the price in Ontario is $40 for all intervals. The price in the New York zone, therefore, is negative $60 (Ontario MCP of $40 plus the ICP of -$100).

CMSC for Transbord in this situation would be:

CMSC = Operating Profit Unconstrained – Operating Profit Constrained

= [(-$60 - $25) X 100] - [(-$60 - $25) X 0]

= -$8,500

Transbord would owe the IESO $8,500. However, Transbord is also eligible for an IOG that would entirely offset the negative CMSC in this example:

IOG = -1 X ((Intertie Zone MCP – Offer) X Market Schedule Quantity)

= -1 X ((-$60 - $25) X 100 MW)

= -1 X (-$8,500)

= $8,500

Skill Check

1. True or False:
   a. The intertie offer guarantee applies to exports as well as imports.
2. What would the IOG be for Genbord assuming the following:
   a. Offered 100 MW at $35
   b. Pre-dispatch intertie zone price and Ontario price of $40
   c. 100 MW market schedule
   d. Intertie zone price in real-time of $25
3. What would the IOG be for Transbord assuming the following:
   a. Offered 150 MW at $40
   b. Pre-dispatch intertie zone price and Ontario price of $45
   c. 150 MW market schedule.
   d. Intertie zone price in real-time of $50 for the first 8 intervals and $30 for last 4 intervals
4. True or False:
   a. The intertie offer guarantee will normally offset a negative congestion management settlement credit.
5. True or False:
   a. The intertie offer guarantee is paid on total imports during the hour regardless of exports also scheduled during the hour.

Skill Check: Answers

1. True or False:
   a. The intertie offer guarantee applies to exports as well as imports: **FALSE**
2. What would the IOG be for Genbord assuming the following:
   a. Offered 100 MW at $35
   b. Pre-dispatch intertie zone price and Ontario price of $40
   c. 100 MW market schedule
   d. Intertie zone price in real-time of $25

Answer:

IOG = -1 X ((Intertie Zone MCP – Offer) X Market Schedule Quantity)

= -1 X (($25 - $35) X 100 MW)

= -1 X (-$1,000)

= $1,000

3. What would the IOG be for Transbord assuming the following:
   a. Offered 150 MW at $40
   b. Pre-dispatch intertie zone price and Ontario price of $45
   c. 150 MW market schedule.
   d. Intertie zone price in real-time of $50 for the first 8 intervals and $30 for last 4 intervals

Answer:

IOG would be $0 as the positive operating profit from the first 8 intervals ($50

- $40 = $10 for 8 intervals) more than offsets the negative operating profit from the last 4 intervals ($30 - $40 = -$10 for 4 intervals)

4. True or False:
   a. The intertie offer guarantee will normally offset a negative congestion management settlement credit: **TRUE**
5. True or False:
   a. The intertie offer guarantee is paid on total imports during the hour regardless of exports also scheduled during the hour: **FALSE**

7. Limitations on CMSC Payments

Congestion management settlement credits (CMSC) are designed to return a market participant to its market schedule operating profit in situations where the dispatch schedule is different from the market schedule. Underlying this is the assumption that the market participant offered energy at its marginal cost, or bid for energy at its marginal benefit. If this is the case, the payment of CMSC ensures that the market participant does not suffer an actual loss as a result of being constrained on or off. Over time, several circumstances have been identified under which this assumption of marginal cost/benefit bidding could not be supported.[12] In response, the IESO has instituted a number of market rule changes placing restrictions either on the payment of CMSC, or on how the IESO analyzes transactions which result in CMSC. This section explains these rules as they relate to intertie transactions.[13]

Objectives

After completing this section you will be able to:

- Discuss how CMSC is calculated for constrained-off imports with negative offer prices
- Explain reference prices
- Define an uncontested intertie
- Explain how reference prices are used when considering CMSC paid for constrained- off exports at uncontested interties

CMSC for Constrained-Off Imports with Negative Offers

The market rules allow importers to offer energy at a price as low as negative $2,000. Offering in this way virtually guarantees that the import will be scheduled in the unconstrained (or market) schedule (assuming sufficient intertie capacity). However, conditions on the IESO-controlled grid may result in the import being constrained off. Let's look at an example:

- Borgpower offers to import 100 MW from Michigan at -$1,000
- Borgpower receives a market schedule for all 100 MW
- However, due to a system constraint within Ontario, Borgpower is constrained-off and receives a 0 MW dispatch schedule
- Michigan market clearing price in real-time is $20 for all intervals

[12] For example, see the report "Constrained-Off Payments and Other Issues in the Management of Congestion" available on the Market Surveillance Panel pages of the Ontario Energy Board web site.

[13] Note: The procedures described also apply to transactions by generators and loads within Ontario, where applicable.

Therefore:

CMSC = Operating Profit Unconstrained – Operating Profit Constrained

= (($20 - -$1000) x 100 MW)) - (($20 - -$1000) x 0 MW)

= $102,000

This kind of payment is not truly consistent with the underlying CMSC assumption of marginal cost offers. It is highly unlikely that the actual marginal cost to a supplier would ever be less than $0. As a result, if CMSC is payable for a constrained-off import that was offered at a negative price, the IESO recalculates the CMSC so that the market participant receives payments as if they had offered at $0.

Looking at our example again, the CMSC payment for this market participant would be recalculated as follows:

CMSC = (($20 - $0) x 100 MW) - (($20 - $0) x 0 MW)

= $2,000

CMSC and Reference Prices

The IESO examines all instances where a material amount of CMSC has been paid. This is to ensure that such payment did not result from the application of market power.[14] Payments may be reduced if investigations reveal that CMSC resulted from inappropriate circumstances.

One of checks the IESO performs is to compare the offer or bid made by the market participant at the time the CMSC was incurred against two reference prices:

- The market clearing price for the interval or intervals during which the CMSC was incurred, and
- The resource's historical reference price. The historical reference price is the average offer or bid by the participant that was accepted in the market schedule over the 90- day period prior to when the CMSC was incurred. Two historical reference prices are used: One for the period 7:00 to 23:00 EST on business days, and another for all other times.

[14] Materiality for this purpose is defined in *Market Manual 2.12, Treatment of Local Market Power, Appendix C.4* available on the IESO Rules, Manuals and Forms web page.

When evaluating an incident, a “safe-harbour” of acceptable offers or bids is established around the MCP and the historical reference price:

- The upper limit is 110% to 150% of the price
- The lower limit is 70% to 90% of the price

These limits are adjusted based on such factors as the duration over which the current CMSC payment was made, and the number of times CMSC was incurred by the market participant over the last 90 days.

Let’s look at an example of how reference prices might be used. Assume:

- A CMSC payment was incurred at a time when the market clearing price was $24.
- The market participant involved has a calculated historical reference price of $44.
- Based on the factors mentioned above, the range around the prices is set at a low of 75% of the price and a high of 125% of the price
- As a result, the range of acceptable prices is from 75% of $24 (the lowest price) to 125% of $44 (the highest price).

Therefore, the price range in this example would be:

- $24 x 75/100 = $18
- $44 x 125/100 = $55

If the bid or offer the market participant made at the time the CMSC was incurred was more than $18 for a constrained-off import or a constrained-on export, or was less than

$55 for a constrained-on import or constrained-off export, the IESO will cease investigating. If otherwise, the IESO will continue to examine the incident. If it is determined that action is required, the IESO will recalculate the CMSC payment substituting the appropriate high-end or low-end price for the market participant’s bid or offer as follows:

The high-end price (in this example, $55) would be used if:

- The incident involved a constrained-on import, and the offer exceeded the market clearing price, or
- The incident involved a constrained-off export, and the bid exceeded the market clearing price.

A low-end price (in this example, $18) is used if:

- The incident involved a constrained-off import; offer was below the market clearing price, or
- The incident involved a constrained-on export; bid was below the market clearing price.

CMSC, Reference Prices and Constrained-Off Exports at Uncontested Interties

The above describes the standard use of reference prices for evaluating CMSC. The market rules have a provision that affects how reference prices are used in cases of constrained-off exports at uncontested interties.

An intertie is defined as uncontested for exports if:

- At least 90% of the withdrawals over the intertie in the previous 90-day period were accomplished by one market participant, or
- The IESO finds reasonable grounds to believe that one or more participants effectively control the level of CMSC payments from export transactions on a particular intertie (see *Market Manual 2-12: Treatment of Local Market Power, Appendix E* for specific criteria).

As stated above, one of the assumptions underlying CMSC is that market participants bid for energy at their marginal benefit. In other words, if you bid $100 for energy, it is assumed that you derive a benefit of $100 by consuming that energy.

However, for exports, this is not always the case. A market participant may bid a high price in order to increase the likelihood of their transaction being scheduled. As long as the intertie is uncongested, they will pay only the Ontario market clearing price.

Congestion is much more likely to occur on a contested intertie than on an uncontested one. On uncontested interties, competition does not exist to a sufficient extent. As a result, a market participant can consistently bid a high price in order to increase the likelihood of being scheduled in the knowledge that there is little or no possibility that the intertie will become export-congested. Therefore, they know that they are almost certain to pay only the Ontario MCP and not their high bid price (see *Section 3: Pricing and Scheduling of Interjurisdictional Trade*).

While bidding in this manner is allowable under the market rules, it has two potential impacts on CMSC:

- If the transaction is constrained-off, a high CMSC payment will occur
- This bidding behaviour creates a high historical reference price because it is based on the market participant's own accepted bids over the last 90 days. An artificially high reference price can limit the effectiveness of the IESO's investigations.

In order to counter these effects, only the current zonal market clearing price is used as a reference price when the IESO analyzes CMSC payments at uncontested interties. The historical reference price is not used. Therefore, the IESO will further assess market participants operating at uncontested interties if the market participant bid for energy outside of the acceptable range around the current zonal market clearing price.

The designation of intertie zones as uncontested can change over time. The IESO monitors conditions at each designated intertie, and if it is determined that an intertie is no longer uncontested, the designation is revoked. Additionally, any market participant can request that the designation be revoked as long as they provide information supporting the request.

As of the date of this document, the PQHZ and PQAT intertie zones with Quebec have been designated as uncontested. The criteria for designating an intertie as uncontested and for revoking such designation are explained in the following documents, available on the IESO Rules, Manuals and Forms web page:

- Section 1.3.3.4 of *Appendix 7.6* of the market rules
- *Market Manual 2.12; Treatment of Local Market Power, Appendix E*

Skill Check

1. True or False:
   a. Limitations on CMSC payments were placed because the Market Surveillance Panel identified situations in which the underlying assumption of marginal cost/benefit bidding did not hold
2. What would Transbord's CMSC payment be assuming the following:
   a. Transbord offered to import 200 MW from New York at -$100
   b. Their market schedule is 200 MW, but a constraint inside Ontario reduces their dispatch schedule to 0 MW
   c. New York zone price is $35 for all intervals in real-time
3. Which of the following are **not** used as reference prices when examining constrained-off exports at uncontested interties:
   a. The market clearing price for the interval or intervals during which the CMSC was incurred
   b. The price in the neighbouring control area at the time the CMSC was incurred
   c. The resource's historical reference price
   d. The price in the zone during the last hour in which the participant could have entered a bid to export
4. Which of the following is a criteria for establishing that an intertie is uncontested for exports:
   a. At least 90% of the withdrawals over the intertie in the previous 60-day period were accomplished by one MP
   b. At least 90% of the withdrawals over the intertie in the previous 90-day period were accomplished by one MP
   c. If the IESO finds reasonable grounds to believe that one or more participants effectively control the level of CMSC payments from export transactions on a particular intertie

Skill Check: Answers

1. True or False:
   a. Limitations on CMSC payments were placed because the Market Surveillance Panel identified situations in which the underlying assumption of marginal cost/benefit bidding did not hold: **TRUE**
2. What would Transbord's CMSC payment be assuming the following:
   a. Transbord offered to import 200 MW from New York at -$100
   b. Their market schedule is 200 MW, but a constraint inside Ontario reduces their dispatch schedule to 0 MW
   c. New York zone price is $35 for all intervals in real-time

CMSC = (($35 - $0) x 200 MW) - (($35 - $0) x 0 MW)

= $7,000

3. Which of the following are **not** used as reference prices when examining constrained-off exports at uncontested interties:
   a. The market clearing price for the interval or intervals during which the CMSC was incurred
   b. **Answer 1**: The price in the neighbouring control area at the time the CMSC was incurred
   c. **Answer 2**: The resource's historical reference price
   d. **Answer 3**: The price in the zone during the last hour in which the participant could have entered a bid to export
4. Which of the following is a criterion for establishing that an intertie is uncontested for exports:
   a. At least 90% of the withdrawals over the intertie in the previous 60-day period were accomplished by one MP
   b. **Answer 1**: At least 90% of the withdrawals over the intertie in the previous 90-day period were accomplished by one MP
   c. **Answer 2**: If the IESO finds reasonable grounds to believe that one or more participants effectively control the level of CMSC payments from export transactions on a particular intertie

8. Net Interchange Schedule Limit

The direction and volume of net energy flow on an intertie is the result of the combination of imports and exports scheduled for the hour. For example, 1,000 MW of imports and 1,000 MW of exports scheduled for the same hour results in a 0 MW net flow. Having too great a change in intertie flow from one hour to another can adversely affect reliability in Ontario. To prevent this, the IESO imposes a net interchange schedule limit.

Objectives

After completing this section you will be able to:

- Explain why a net interchange schedule limit must be used
- Explain how the net interchange schedule limit is applied, both automatically and manually
- Given a net schedule for one hour, calculate the acceptable interchange schedule range for the next hour
- Discuss when CMSC may be affected by the net interchange schedule limit

Why Limit Changes in the Interchange Schedule?

Interchange schedules are for one hour periods starting at the beginning of an hour. As a result, the net flows across the interties can change across the top of the hour each and every hour.

Changes in intertie flow are achieved by ramping resources within Ontario either up or down. This either draws energy into Ontario or moves energy out. Resource ramping is achieved over a ten-minute period starting five minutes before the dispatch hour and ending five minutes after the start of the dispatch hour. The larger the net change in intertie flow from one hour to the next, the more difficult it is for resources within Ontario to accommodate the change. For example, a 1,000 MW increase in net exports would need to be ramped at a rate of 100 MW/min over the ten-minute period. This could require 20 generation units to each ramp up at a rate of 5 MW/min.

Responding to large hourly interchange schedule changes can have an adverse impact on the reliability of the IESO-controlled grid. To prevent these problems, Ontario's IESO limits the change in the net interchange schedule from hour-to-hour by imposing a net interchange schedule limit (also referred to as the “inter-hour ramp limit”).

Typically the IESO limits the net change from one hour to the next to 700 MW.[15] This change can be in either direction (i.e., either 700 MW more into or out of the province). For example, if the net schedule in one hour is 600 MW of imports, in the next hour the

[15] Unless respecting this limit would negatively impact reliability, such as during a supply shortfall

schedule could be for up to 1300 MW of imports or 100 MW of exports (i.e., 600 MW currently flowing plus 700 MW or minus 700 MW). This limiting of interchange transaction schedules occurs automatically within the Dispatch Scheduling Optimizer (DSO), or, if necessary, manually through IESO intervention. Both processes are discussed below.

Automatic Process

The DSO attempts to schedule transactions that in combination do not violate the 700 MW net interchange schedule limit. In achieving this, transactions that would

otherwise have been economic may not be fully scheduled or may not be scheduled at all. Alternatively, the DSO may respect the limit by scheduling transactions that might not otherwise have been selected. As with all scheduling decisions, the DSO uses an economic basis to determine how to ensure compliance with the net interchange schedule limit.

We can illustrate this process with an example. For the sake of simplicity, we will assume there is only one intertie zone with no congestion.

Assume that in Hour Ending (HE) 1, the total net interchange schedule is 500 MW coming into the province (i.e., imports). The allowable net change from this schedule is plus or minus 700 MW. Therefore, the total net interchange schedule for the next hour must be within the range of:

- 1200 MW of net imports (500 MW of current net imports plus 700 MW of additional imports) or
- 200 MW of net exports (500 MW of current net imports plus 700 MW of exports).

Assume that during the pre-dispatch process for HE 2, the IESO-administered market receives the following bids and offers:

Transbord	Import 1300 MW @ $30
Pinepower	Import 300 MW @ $35
Expbord	Export 100 MW @ $50
Genbord	Export 300 MW @ $34

In pre-dispatch, the MCP for Ontario is $38 and there is no congestion on the intertie. With an MCP of $38, the import offers by Transbord and Pinepower and the export bid by Expbord are all economic. The export bid by Genbord is not economic (Genbord is only willing to pay $34/MW for its 300 MW export and the MCP is $38). If all of the economic transactions were allowed to flow, the net interchange schedule would be:

Transbord Pinepower Expbord

1300 MW import + 300 MW import - 100 MW export = 1500 MW of imports. However, as explained above, the total net interchange schedule for HE 2 can be no greater that 1200 MW of imports. Additional imports would violate the net interchange schedule limit. In order to respect the limit, the DSO must reduce the 1500 MW to 1200 MW. This can be achieved by either scheduling 300 MW less of imports, or by scheduling 300 MW of additional exports. How will the DSO decide which measure to take?

The DSO attempts to maximize gain from trade across the market when scheduling transactions. Gain from trade is the sum of supplier and consumer operating profit:

- Supplier operating profit is the difference between the supplier's offer price and the revenue they receive (i.e., MCP, less their offer).
- Consumer operating profit is the difference between what they are willing to pay for energy and what they are required to pay (i.e., their bid, less MCP).

One alternative open to the DSO in the example is to schedule 300 MW of exports. This would reduce the net interchange schedule to the required 1200 MW of imports.

Genbord bid to export 300 MW of energy if the price was $34 or less. The MCP was $38. If Genbord's export were scheduled to allow the DSO to respect the net interchange schedule limit, Genbord would lose $4/MW. Therefore, scheduling Genbord would result in a $1,200 reduction in consumer operating profit (and thereby, a reduction in the gain from trade in Ontario).

($34 - $38) X 300 MW = -$1,200

There is another way the DSO could respect the limit. It could reduce imports by

300 MW. There were two import offers in this example: One from Pinepower and one from Transbord. Which should the DSO consider reducing?

Transbord offered at $30 and Pinepower offered at $35. MCP was $38. This means that for each MW scheduled, Transbord has an operating profit of $8 ($38 - $30) against Pinepower's $3 ($38 - $35). Because its operating profit is less, the DSO will consider reducing Pinepower in preference to reducing Transbord because doing so has less of an impact on supplier operating profit (and thereby gain from trade for the market).

Pinepower offered 300 MW. Reducing this import to 0 MW will allow the DSO to satisfy the net interchange schedule limit. This action would lower the gain from trade to the market as a whole by all of Pinepower's potential operating profit:

($38 - $35) x 300 MW = $900

Scheduling Genbord's export would reduce the gain from trade by $1,200. Therefore, the DSO in this example would reduce Pinepower's import to meet the net interchange schedule limit. The resulting interchange schedule for HE 2 would be:

Transbord	Import 1300 MW @ $30
Expbord	Export 100 MW @ $250
Pinepower	Import 0 MW
Genbord	Export 0 MW

Manual Process

In the above example, the DSO was able to use available bids and offers to avoid violating the 700 MW net interchange schedule limit. What happens if insufficient bids or offers are available? When this occurs, the DSO can't create a schedule that does not violate the limit. Therefore, the IESO has to act manually to ensure that the limit is respected in order to support system reliability.

If it is determined more than five hours prior to the dispatch hour that the potential exists for a violation of the net interchange schedule limit that the DSO can't avoid, the IESO will attempt to avoid the violation by sending messages to the market via the System Status Report. These messages request that participants voluntarily adjust their bids and offers to help correct the problem.

If the situation persists, or if it is initially identified less than five hours in advance, the IESO must directly intervene. The IESO will manually adjust intertie schedules in the hour before the hour with the violation in order to avoid the problem. If manual adjustments are required, the following principles are used to guide the IESO's actions:

- Only transactions that contribute to the net interchange schedule limit violation are reduced (i.e., transactions that changed from the previous hour, excluding linked wheel-through transactions)
- To the extent possible, transactions are reduced in the most economic order
- When two or more transactions have the same price, each transaction will be reduced on a pro-rated basis

We can see how this works through an example.

The IESO receives the following offers to import energy from New York:

Import Offers				
Hour Ending	1	2	3	4
Transbord	400 MW @ $75	400 MW @ $75	400 MW @ $75	400 MW @ $75
Powerport	600 MW @ $65	600 MW @ $65	700 MW @ $65	No offer
Borgpower	No offer	700 MW @ $60	700 MW @ $60	No offer
Total Net Intertie Schedule	1,000 MW	1,700 MW	1,800 MW	400 MW
Change from previous hour	N/A	700 MW	100 MW	1400 MW

Assume that the Ontario MCP and the price in the New York zone are above $100 for each of the four hours. In this case, all offers would be economic as they were all below $100. Assume further that the zone price is the same as the price in Ontario for each hour (i.e., ICP = $0).

We can see that a problem exists from HE 3 to HE 4. There is a 1400 MW hour-to-hour change. However, 700 MW is the most that can be allowed. The DSO would normally use the bids and offers available in the hour to find a combination that would respect the limit. However, there is only one offer in HE 4. Cutting the offer would not improve the situation as the net interchange schedule change would actually go up, not down as needed. The DSO can't constrain on Powerport or Borgpower, either, as they have withdrawn their offers. Ideally, the DSO would change the schedules in HE 3 in order to avoid problems in HE 4 when the two import offers are withdrawn. However, the DSO is not capable of doing this on its own. It can only look out one hour when scheduling.

Therefore, when setting the schedules for HE 3 during HE 2, the DSO doesn't recognize that there is a problem in HE 4. As a result, the IESO would have to take manual action in HE 3 to prevent the limit violation in HE 4.

In order to respect the net interchange schedule limit, the IESO must ensure that the import total in HE 3 is no more than 1100 MW. This is arrived at by adding the 700 MW limit to the 400 MW of imports that will be available in HE 4.

How is this to be accomplished? The first decision-making principle cited above states that only those transactions that contribute to the problem should be affected. In this example, who contributed to the problem? Transbord has the same offer in HE 4 that it had in HE 3, whereas both Powerport and Borgpower withdrew their offers in HE 4.

Therefore, only Powerport and Borgpower contribute to the problem. Only their transactions will be considered for reduction in HE 3.

The second principle cited above is that transactions will be reduced in economic order. Powerport has a lower operating profit than Borgpower because Powerport's offer was higher. Therefore, Powerport would be reduced before Borgpower.

As stated above, the IESO has to reduce net imports from 1800 MW to 1100 MW in HE 3. This can be achieved by reducing Powerport's HE 3 schedule to 0 MW:

Hour	1	2	3	4
Transbord	400 MW @ $75	400 MW @ $75	400 MW @ $75	400 MW @ $75
Powerport	600 MW @ $65	600 MW @ $65	0 MW	No offer
Borgpower	No offer	700 MW @ $60	700 MW @ $60	No offer
Total	1,000 MW	1,700 MW	1,100 MW	400 MW
Change from previous hour	N/A	700 MW	- 600 MW	- 700 MW

The 700 MW limit is now respected in all hours.

Congestion Management Settlement Credits (CMSC) and the Net Interchange Schedule Limit

The net interchange schedule limit is applied in the same way in both the unconstrained and constrained modes of the DSO. This means that CSMC cannot be caused directly by the application of the net interchange schedule limit.

However, the starting conditions for the constrained and unconstrained modes may differ. This is typically because of transmission congestion within Ontario. This means that even though the net interchange schedule limit is applied in the same way in both modes, the outcomes of this application can differ because the starting conditions differed. In some circumstances, this difference may result in CMSC payments.

The following example illustrates the interaction of internal transmission limits and the net interchange schedule limit. Assume:

In **Hour One:**

- There is a single offer from Transbord to import 700 MW of energy at $10/MW

- Internal constraints limit the actual allowable flow to 500 MW
- MCP is $50
- The market schedule is a net import of 700 MW
- The dispatch schedule is a net import of 500 MW

In Hour One, there will be a CMSC payment to Transbord based on the lost operating profit from the 200 MW that did not flow due to internal constraints. (CMSC in this case is $8,000, which is $40 lost operating profit per megawatt, times 200 MW.)

In **Hour Two**:

Even though both the constrained and unconstrained modes of the algorithm use the exact same net interchange schedule limit of 700 MW, they have different starting points when determining an acceptable net schedule for Hour Two. The constrained mode uses the actual operating point from the previous period, whereas the unconstrained mode uses the last market schedule.

Applying the net interchange schedule limit of 700 MW means that in Hour Two:

- The unconstrained mode will allow a net interchange schedule range of 1400 MW of imports to 0 MW of flow (that is, the previous hour's 700 MW market schedule, plus or minus 700 MW)
- The constrained mode will allow a net interchange schedule range of 1200 MW of imports to 200 MW of exports (that is, the previous hour's dispatch schedule of 500 MW, plus or minus 700 MW)

What does this mean for our example? Assume that in Hour Two:

- There are no import offers
- Borgpower enters a new bid to export 200 MW of energy at $75/MW
- MCP is $50

The unconstrained mode will only allow a net interchange schedule range of 1400 MW of imports to 0 MW of flow. Allowing Borgpower's export would result in a net flow of 200 MW out of the province, or a total net interchange schedule change of 900 MW. Although Borgpower's bid is economic, the net interchange schedule limit would not allow the export. Borgpower would receive a 0 MW market schedule.

The constrained mode, however, has an allowable net interchange schedule range of 1200 MW of imports to 200 MW of exports. This is because its starting point from Hour One was 500 MW of imports, not the 700 MW of imports assumed by the unconstrained mode. As a result, Borgpower would receive a dispatch schedule allowing it to export all 200 MW.

Because of these different schedules, Borgpower would have an operating profit under its dispatch schedule, but not under its market schedule. CMSC is used to ensure that a participant is held to the operating profit that they would have received under their market schedule. In this case, there would be a negative CMSC payment, or a charge, to Borgpower:

CMSC = (($75 - $50) x 0 MW) - (($75 - $50) x 200 MW)

= -$5,000

The negative CMSC payment is the result of the different starting points used by the unconstrained and constrained modes of the algorithm. If there had been no congestion in Hour One, the starting points would have been the same for both modes, and, since both use the same net interchange schedule limit, there would have been no CMSC payment.

Note, however, that Borgpower does not have a negative operating profit even with this charge. Combining the negative CMSC payment and the cost of the 200 MW export gives a total transaction cost to that is equivalent to Borgpower's original bid price of

$75/MW:

Cost of export: 200 MW @ $50/MW = $10,000

Negative CMSC: = $ 5,000

Total: = $15,000

Bid price: 200 MW @ $75/MW = $15,000

Skill Check

1. If the current hour has a net interchange schedule of 450 MW of exports, the allowable range for the next hour is:
   a. 700 MW of exports to 700 MW of imports
   b. 1150 MW of exports to 250 MW of imports
   c. 1150 MW of exports to a 0 MW net flow
   d. 1150 MW of exports to 700 MW of imports
2. Which of the following is **not** a principle used when the IESO manually intervenes to respect the net interchange schedule limit:
   a. Only transactions that contribute to the net interchange schedule limit violation are reduced (i.e., transactions that changed from the previous hour, excluding linked wheel-through transactions)
   b. To the extent possible, transactions are reduced in the most economic order
   c. When two or more transactions have the same price, each transaction will be reduced on a pro-rated basis
   d. The more consecutive hours a transaction was scheduled the less likely it is to be reduced
3. Assume that in Hour Ending (HE) 1, the total net interchange schedule is 300 MW going out of the province (i.e., exports). Also assume that during the pre- dispatch process for HE 2, the IESO-administered market receives the following bids and offers.

Transbord	Export 1000 MW @ $50
Pinepower	Import 100 MW @ $30
Expbord	Import 400 MW @ $54
Genbord	Export 300 MW @ $44

If the market clearing price is $36, how would the DSO schedule these transactions?

Skill Check: Answers

1. If the current hour has a net interchange schedule of 450 MW of exports, the allowable range for the next hour is:
   a. 700 MW of exports to 700 MW of imports
   b. **Answer**: 1150 MW of exports to 250 MW of imports
   c. 1150 MW of exports to a 0 MW net flow
   d. 1150 MW of exports to 700 MW of imports
2. Which of the following is not a principle used when the IESO manually intervenes to respect the net interchange schedule limit:
   a. Only transactions that contribute to the net interchange schedule limit violation are reduced (i.e., transactions that changed from the previous hour, excluding linked wheel-through transactions)
   b. To the extent possible, transactions are reduced in the most economic order
   c. When two or more transactions have the same price, each transaction will be reduced on a pro-rated basis
   d. **Answer**: The more consecutive hours a transaction was scheduled the less likely it is to be reduced
3. Assume that in Hour Ending (HE) 1, the total net interchange schedule is 300 MW going out of the province (i.e., exports). Also assume that during the pre-dispatch process for HE 2, the IESO-administered market receives the following bids and offers.

Transbord	Export 1000 MW @ $50
Pinepower	Import 100 MW @ $30
Expbord	Import 400 MW @ $54
Genbord	Export 300 MW @ $44

If the market clearing price is $36, how would the DSO schedule these transactions?

Answer:

With a market clearing price of $36 the following transactions would be economic:

Transbord	**Export 1000 MW @ $50**
Pinepower	**Import 100 MW @ $30**
Genbord	**Export 300 MW @ $44**

This would result in a net interchange schedule of:

1000 MW export - 100 MW import + 300 MW export = 1200 MW of exports

Given the net schedule of 300 MW of exports in HE 1, this would violate the limit of 1000 MW of exports. The DSO needs to cut 200 MW of exports or schedule an additional 200 MW of imports. The DSO would make this determination based on which option had the least impact on the gain from trade. The DSO has three options:

a. **It could reduce Transbord's export by 200 MW. This would reduce the gain from trade as follows: (50 – 36) X 200 = $2,800**

b. **It could schedule 200 MW of imports from Expbord. Because Expbord offered at higher than the market clearing price, scheduling its transaction would cause a loss in gain from trade as follows: (36 – 54) X 200 = -$3,600**

c. **It could reduce Genbord's export by 200 MW. This would reduce the gain from trade as follows: (44 – 36) X 200 = $1,600**

Given that reducing Genbord by 200 MW has the least impact on the gain from trade (a reduction in gain from trade of $1,600 versus $2,800 or $3,600), the DSO would select this option. The final schedule would be:

Transbord	**Export 1000 MW @ $50**
Pinepower	**Import 100 MW @ $30**
Genbord	**Export 100 MW @ $44**

9. Operating Reserve

As discussed in the *Introduction to Ontario's Physical Markets* workbook (available on the Training web pages), operating reserve (OR) is essentially stand-by power or demand reduction that can be called upon with short notice to deal with an unexpected mismatch between generation and load. OR helps the IESO ensure the reliability of the grid by forming a pool of additional energy that can be accessed quickly to boost supply if needed.

There are three classes of operating reserve, determined by the time required to bring the energy into use and the physical behaviour of the facilities that can provide it:

- 10 minute spinning (synchronized)
- 10 minute non-spinning (non-synchronized)
- 30 minute

The IESO administers a market for all three types of operating reserve. This allows the IESO to purchase this service in the most efficient manner possible. Those dispatchable market participants who wish to supply OR offer it to the market. Dispatchable suppliers offer to provide additional energy, and dispatchable consumers offer to reduce their demand if called upon. A market clearing price for each class of operating reserve is set based on the requirement for each class (as set by the IESO based on industry reliability standards), and the cost of the offers submitted.

The market rules allow the IESO to obtain non-spinning OR from imports and exports. However, this is restricted to interties where the IESO has the agreement of the neighbouring control area that these transactions can be treated as OR. (NOTE: Even where this agreement exists, intertie transactions cannot be offered as synchronized reserve).

Additionally, participants cannot export OR from Ontario to another jurisdiction.

10. Settlement

Intertie transactions are settled on the same timelines and with the same processes as those used for physical transactions within Ontario.

Objectives

After completing this section you will be able to:

- Explain settlement timelines
- Identify constraints that cause CMSC to be paid
- List common uplift charges
- Explain an importer's role with regard to the Harmonized Sales Tax (HST)

Timing of Settlement Statements and Invoices

Recall from *Section Two: Interjurisdictional Energy Transactions* that imports are essentially the same as generators within Ontario and exports are generally the same as loads within Ontario. This is also true for the settlement process. The timing for settlement in the physical market is outlined below. (Please see the recorded presentation *Commercial Reconciliation* or the *Settlement Statements and Invoices* workbook for more information on the settlement process. Both are available on the Training web pages).

Transactions occur in the IESO-administered markets 24-hours a day, 365 days a year. Therefore, every day is a trade day that must be settled. For each trade day:

- A preliminary settlement statement is issued 10 business days after the trade day.
- A final settlement statement is issued 10 business days after the preliminary settlement statement, or 20 business days after the trade day.

Invoices in the physical markets are issued for a calendar month, 10 business days after the last trade day of the month.

Those who owe the market (e.g., net exporters) must make payments to the IESO within two business days of invoices being issued.

The IESO, in turn, makes payments within four business days of invoices being issued to those participants who are owed by the market (e.g., net importers).

The totals on statements and invoices are divided into categories referred to as charge types (please see the *Charge Types and Equations* document available on the Technical Interfaces web page for more details). For example, imports and exports are settled in charge type 100, Net Energy Settlement for Dispatchable Market Participants (recall that intertie transactions are considered dispatchable prior to the hour in which they actually flow).

The settlement amount for imports and exports is based on the appropriate intertie zone price and the scheduled flow (assuming that the transaction does not fail). NERC tags are not used to determine settlement amounts. (NERC tags may be used during follow- up investigations if there is uncertainty or disagreement on actual flows.)

Operating reserve purchased by the IESO from importers and exporters is settled in charge type 203 (ten-minute non-spinning) and charge type 208 (30-minute).

Intertie offer guarantee (IOG) payments are made in charge type 130. Recall that these payments are made only on net imports. They do not apply to wheel-through transactions, whether linked or unlinked. If an IOG payment is calculated on the import leg of a wheel-through, there will be a balancing IOG offset amount in charge type 130 which will bring the net IOG to zero. This adjustment is made on the last preliminary settlement statement for the month.

Congestion Management Settlement Credits (CMSC)

As discussed in Section 4, the IESO uses CMSC to remove the impact on participant's operating profit of constraints on the IESO-controlled grid. CMSC is not payable when schedules are affected by constraints on an intertie or in another control area.

CMSC is covered in charge type 105 (recall that CMSC can be negative, requiring a payment to the IESO).

Participants can retrieve a data file along with their preliminary settlement statement. The schedule section of the data file (begins with the letter S) identifies transactions that were limited by internal or external constraints. Constraints that were internal to Ontario (i.e., on the IESO-controlled grid) are flagged with a TLRi code while external constraints are identified with TLRe. CMSC is paid only where the constraint was internal.

Congestion payments for operating reserve appear in charge type 107 (ten-minute non- spinning) and charge type 108 (30 minute).

Uplift

The IESO is a revenue neutral organization. Revenues received from energy consumers must equal payments to suppliers, plus expenses. Overhead, reliability expenses, and losses are recovered by tariffs and uplift charges. Those withdrawing energy pay virtually all of these costs (the only exception being a default levy which can be used to recover losses from ALL participants, including suppliers, if a participant defaults on payments to the IESO-administered markets).

Exports withdraw energy from the IESO-controlled grid and are, therefore, subject to tariffs and uplift charges. Some uplifts are calculated hourly, while others are calculated monthly.

Hourly uplifts include:

- 150: Net Energy Management Settlement Credit
- 155: Congestion Management Settlement Credit
- 250, 252, 254: Three classes of operating reserve

The total of all hourly uplifts is estimated an hour after the trade hour, and is posted on the Today's Market page of the IESO web site.

Monthly uplifts include:

- 450, 452, 454: Monthly Ancillary Services
- 9990: IESO Administration Charge
- 653: Export Transmission Service Charge

The *Settlement Statements and Invoices* workbook provides more detail on common charges. A complete list of all possible charges is contained in the IESO document, *IESO Charge Types and Equations* available on the Rules, Manuals and Forms web page.

There are some uplifts which do not apply to exports. Exports do not pay the Debt Retirement Charge, the Rural and Remote Settlement Credit, or the Global Adjustment. In addition, there is a separate transmission tariff for exports (Charge Code 653).

Information on historical uplift charges can be found in the *Market Summaries* posted on the IESO's website.

Harmonized Sales Tax (HST)

Statements and invoices include charge codes for the HST:

- Charge Code 950 for HST amounts due to the IESO from the participant
- Charge Code 900 for HST owed from the IESO to the participant

The HST is intended to be a tax on consumption within Canada. Therefore, the HST:

- is not charged on exports of energy to non-Canadian jurisdictions (i.e., New York, Michigan and Minnesota)
- is payable by the IESO to participants importing to Ontario from the United States

For more information on the HST in the IESO-administered markets including the responsibilities of importers and exporters, please see the *HST Guide for IESO Transactions* available on the Rules, Manuals and Forms page of the IESO web site.

Notice of Disagreement (NOD)

If a participant believes that an error has occurred on their preliminary settlement statement, they can file a notice of disagreement. The filing deadline is 4 business days from when the statement was made available. Please note that filing a NOD does not change the time period for paying an invoice. For more information on the process for filing a NOD, please see the *Settlement Statements and Invoices* workbook available on the Training web pages.

NOTE: For information on the Day-Ahead Intertie Offer Guarantee, please see:

- The Guide to the Day-Ahead Commitment Process
- The Intertie Transactions recorded presentation available on the Day-Ahead Commitment Process Training page
- Market Manual 9.5: Settlement for the Day-Ahead Commitment Process available on the Rules and Manuals page

Skill Check

1. Which of the following statements are False:
   a. Preliminary settlement statements are available 10 business days after each trade day.
   b. Final settlement statements are available 10 days after the trade day.
   c. You can file a Notice of Disagreement against your final settlement statement.
   d. If a TLRi code is seen in a data file, CMSC is payable for that transaction.
2. How often must importers remit HST?
   a. Biannually
   b. Every 2 months
   c. Monthly
   d. Quarterly
3. True or False:
   a. There will be an offsetting intertie offer guarantee charge in charge type 130 for implied wheel-throughs.
4. How many days does a participant have to file a NOD?
   a. 2 business days after the preliminary settlement statement is made available
   b. 10 business days after the preliminary settlement statement is made available
   c. 4 business days after they retrieve the preliminary settlement statement
   d. 4 business days after the preliminary settlement statement is made available

Skill Check: Answers

1. Which of the following statements are False:
   a. Preliminary settlement statements are available 10 business days after each trade day.
   b. **False**: Final settlement statements are available 10 days after the trade day.
   c. **False**: You can file a Notice of Disagreement against your final settlement statement.
   d. If a TLRi code is seen in a data file, CMSC is payable for that transaction.
2. How often must importers remit HST?
   a. Biannually
   b. Every 2 months
   c. **Answer**: Monthly
   d. Quarterly
3. True or False:
   a. There will be an offsetting intertie offer guarantee charge in charge type 130 for implied wheel-throughs: **TRUE**

NOTE: The offset will appear on statements for the last trade day of the month.

4. How many days does a participant have to file a NOD?
   a. 2 business days after the preliminary settlement statement is made available
   b. 10 business days after the preliminary settlement statement is made available
   c. 4 business days after they retrieve the preliminary settlement statement
   d. **Answer**: 4 business days after the preliminary settlement statement is made available

11. Compliance with IESO Interchange Schedules

If an interchange transaction fails to flow for a reason that was within the participant's control, that participant is subject to a settlement charge. In some cases, there may also be compliance actions, including penalties.

Objectives

After completing this section you will be able to:

- Explain why interchange failures are significant
- Calculate both an import and an export failure settlement charge

Interchange Failures

Interchange transactions fail to flow for a variety of reasons. Some of these reasons are beyond a participant's control, such as being cut by a system operator. However, participants can avoid others, including:

- Not entering a valid NERC tag
- Not successfully scheduling the transaction in the neighbouring jurisdiction

Interchange failures to flow can have a significant impact on IESO-controlled grid operations and on IESO-administered markets:

- The IESO may have to replace a failed import by taking actions that increase market costs, either through increased uplift or higher prices
- For failed exports, the IESO may have to constrain off generation, leading to increased congestion management settlement credit payments. Such actions may lower the real-time price. Failed exports can also have operational impacts during low demand periods.

Because of these negative effects of failed interchange transactions, an automatic settlement charge is applied to a participant who fails to flow an interchange transaction if the reason for failure was within the participant's control.

Real-time Import Failure Charges: Formula and Example

There is a settlement charge formula for failed import transactions, and one for failed export transactions.

Real-Time Import Failure Charge =

Minimum of:

[Maximum [0,(Real-time Ontario Price + Price Bias Adjustment Factor – Pre-dispatch Ontario Price) X MWh failed],

Maximum (0, Real-time Ontario Price) X MWh failed]

That is, the import failure charge is the lesser of two terms:

- The greater of zero or the real-time Ontario market clearing price adjusted by a Price Bias Adjustment Factor minus the pre-dispatch Ontario market clearing price times the MWh failed
- The greater of zero or the real-time Ontario market clearing price times the MWh failed

The 'price bias adjustment factor' compensates for systematic differences between how prices are calculated in pre-dispatch and how they are calculated in real-time. For example, pre-dispatch is an hourly calculation that projects future prices using expected demand for the hour whereas in real-time, prices are set every five minutes based on actual demand.

The Price Bias Adjustment Factor page of the IESO web site lists the factors. The real-time import failure settlement charge is applied if:

- An import fails in whole or in part for a reason that was within the participant's control, and
- The real-time price in Ontario is higher than the last pre-dispatch price for that hour. The last-pre-dispatch price is the one calculated by the final pre-dispatch run before the start of the hour during which the energy should have flowed. For example, the last pre-dispatch price for hour ending 5 would have been determined by the 3:07 pre-dispatch run.

The second term of the formula means that the real-time import failure settlement charge cannot be more than an amount equal to the real-time Ontario price times the MWh failed.

Assume:

- Pre-dispatch Ontario price = $35
- Real-time Ontario price = $45
- 10 MWh failed in hour ending 6 on September 3, 2012
- Price bias adjustment factor = $2.74

Real-Time Import Failure Charge:

= Minimum of

[Maximum [0,(Real-time Ontario Price + Price Bias Adjustment Factor – Pre-dispatch Ontario Price) X MWh failed],

Maximum (0, Real-time Ontario Price) X MWh failed]

= Min [Max [0,($45 + $2.74 – $35) X 10], Max(0, $45) X 10]

= Min [$127.40, $450]

= $127.40

Therefore, this participant owes a real-time import failure charge of $127.40.

Real-time Export Failure Charges: Formula and Example

Real-Time Export Failure Charge =

Minimum of

[Maximum [0,(Pre-dispatch Ontario Price – Real-time Ontario Price – Price Bias Adjustment Factor) X MWh failed],

Maximum (0, Pre-dispatch Ontario Price) X MWh failed]

That is, the export failure charge is the lesser of two terms:

- The greater of zero or the pre-dispatch Ontario market clearing price less the real-time price in Ontario less a Price Bias Adjustment Factor times the MWh failed,
- The greater of zero or the pre-dispatch Ontario market clearing price times the MWh failed

The real-time export failure settlement charge is applied if:

- An export fails in whole or in part for a reason that was within the participant's control, and
- The real-time price in Ontario is lower than the last projected pre-dispatch price for that hour

The second term of the formula means that the real-time export failure settlement charge is capped at an amount equal to the pre-dispatch Ontario price times the MWh failed.

Assume:

- Pre-dispatch Ontario price = $55
- Real-time Ontario price = $40
- 40 MWh failed in HE 24 on August 22, 2012
- Price Bias Adjustment Factor = $1.40

Real-Time Export Failure Charge:

= Minimum of

[Maximum [0,(Pre-dispatch Ontario Price – Real-time Ontario Price – Price Bias Adjustment Factor) X MWh failed],

Maximum (0, Pre-dispatch Ontario Price) X MWh failed]

= Min [Max [0,($55 – $40 – $1.40) X 40], Max(0, $55) X 40]

= Min [$544.00, $2200]

= $544.00

Therefore, this participant would owe a real-time export failure charge of $544.40.

NOTE: Import, export and wheel through transactions scheduled by the Day-Ahead Commitment Process that fail to flow in real-time can be subject to a day-ahead failure charge. Please see:

- The Guide to the Day-Ahead Commitment Process
- The Intertie Transactions recorded presentation available on the Day-Ahead Commitment Process Training page
- Market Manual 9.5: Settlement for the Day-Ahead Commitment Process available on the Rules and Manuals page

Compliance Penalties

If an interchange failure is considered 'egregious' (i.e., flagrant), the IESO can:

- Issue a letter of non-compliance
- Impose a financial penalty
- Withhold or claw back payments related to the failed transaction.[16]

A participant who disagrees with the application of a financial penalty or with the withholding or clawback of payments can file a notice of dispute.[17]

A participant who does not agree with the outcome of the dispute can appeal to the Ontario Energy Board.

[16] Please see Market Rules Chapter 3, section 6.6.10A

[17] For more details, see the Dispute Resolution pages of the IESO web site

Skill Check

1. Which of the following is true:

A failed import is a concern because it can cause:

   a. Lower prices
   b. Higher prices
   c. Higher uplift charges
   d. Lower uplift charges

2. The real-time import failure charge is applied if:

   a. The real-time price in Ontario is lower than the last pre-dispatch price for that hour
   b. The real-time price in Ontario is higher than the last pre-dispatch price for that hour
   c. The transaction failed because it was cut by another jurisdiction
   d. The failure was within the participant's control

3. Which of the following are true:

The price bias adjustment factor:

   a. Is needed because the calculation of the real-time price is biased to be lower than the pre-dispatch price
   b. Compensates for systemic differences between how prices are calculated in pre-dispatch and how they are calculated in real-time
   c. Is available on our web site
   d. Is only applied when calculating the real-time import failure charge

4. Assume the following:

   a. Pre-dispatch Ontario price = $30
   b. Real-time Ontario price = $40
   c. 20 MWh import failed in hour ending 18 on February 16, 2011
   d. Price bias adjustment factor = $4.84

Given these factors, the real-time import failure charge be:

   i. $327.55
   ii. $800.00

iii. $296.80

iv. $326.52

Skill Check – Answers

1. Which of the following is true:

A failed import is a concern because it can cause:

   a. Lower prices
   b. **True**: Higher prices
   c. **True**: Higher uplift charges
   d. Lower uplift charges

2. The real-time import failure charge is applied if:

   a. The real-time price in Ontario is lower than the last pre-dispatch price for that hour
   b. **Answer 1**: The real-time price in Ontario is higher than the last pre-dispatch price for that hour
   c. The transaction failed because it was cut by another jurisdiction
   d. **Answer 2**: The failure was within the participant's control

3. Which of the following are true:

The price bias adjustment factor:

   a. Is needed because the calculation of the real-time price is generally biased to be lower than the pre-dispatch price
   b. **Answer 1**: Compensates for systemic differences between how prices are calculated in pre-dispatch and how they are calculated in real-time
   c. **Answer 2**: Is available on the IESO web site
   d. Is only applied when calculating the real-time import failure charge

4. Assume the following:

   a. Pre-dispatch Ontario price = $30
   b. Real-time Ontario price = $40
   c. 20 MWh import failed in hour ending 18 on February 16, 2011
   d. Price bias adjustment factor = $4.84

Given these factors, the real-time import failure charge be:

   i. $327.55

ii. $800.00

iii. **Answer**: $296.80

iv. $326.52

Exhibit "U"

IESO Preparing for the Launch of the Renewed Market – Intertie Traders and Transmission Rights Auction Participants presentation dated April 10, 2025

Exhibit "U"

to the Affidavit of Robin Doolittle

Sworn before me on October 29, 2025, in accordance with O. Reg. 431/20, Administering Oath or Declaration Remotely



Commissioner for Taking Affidavits
(or as may be)

October 29, 2025

Keith Edward Hickey, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.

Expires June 24, 2027.

A1517

Preparing for the Launch of the Renewed Market – Intertie Traders and Transmission Rights Auction Participants

April 10



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This training material has been prepared by the IESO as a training aid for market participants. Users of this training publication are reminded that they remain responsible for complying with all of their obligations under the market rules and associated policies, standards and procedures relating to the subject matter of this training publication, even if such obligations are not specifically referred to herein. While every effort has been made to ensure the accuracy of this training material, users must be aware that the specific provisions of the market rules or particular document posted on the web site of Ontario's Independent Electricity System Operator shall govern.

Agenda

- Overview of the features of the renewed market
- Market Registration
- Day-Ahead Market
- Pre-dispatch
- Real-time
- Linked Wheel-Throughs
- Operating Reserve
- Ex-Post Market Power Mitigation
- Settlements Overview
- Transmission Rights Auction

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Why Market Renewal?

- Ontario's supply mix has changed dramatically over the past twenty years and is set for another seismic change with the significant growth of new energy sources, including clean energy
- The growing complexity and diversity of supply options in the future increases the need for the wholesale market to support efficient dispatch of resources in Ontario and with neighboring jurisdictions, and to signal the necessary investments needed to support system reliability
- Market Renewal will improve how we supply, schedule and price electricity, enabling Ontario's wholesale market to reliably and cost-effectively support sector transformation

Renewed Market Operations

Day-Ahead Market

The DAM calculation engine runs once per day to:

- Produce financially binding day-ahead schedules
- Determine operational commitments for eligible resources
- Perform ex-ante market power mitigation
- Calculate DAM locational marginal prices for settlement

Pre-Dispatch

- Runs hourly to produce advisory schedules and advisory prices for a number of future hours
- Will be enhanced to consider costs, resource limitations and system conditions over the look-ahead period
- Will perform ex-ante market power mitigation

Real-time Market

The real-time calculation engine runs every five minutes to determine:

- Dispatch instructions for the next 5-minute interval and advisory schedules for a number of future intervals
- Intertie transactions are set for the hour
- Settlement-ready locational marginal prices and zonal prices

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Ontario's Current Two-Schedule Market Design

Schedule 1
(Unconstrained)

- Determines a province-wide price for energy (HOEP)
- Ignores certain physical limitations of the system
- Used to settle the market financially

When there are differences between the two schedules, out-of-market Congestion Management Settlement Credit payments must be made to maintain reliability

These payments have led to inefficient behaviour and costly outcomes for consumers

Schedule 2
(Constrained)

- Used to dispatch the system
- Considers all relevant physical limitations of the system
- Calculates "shadow" prices at each node (for information only)

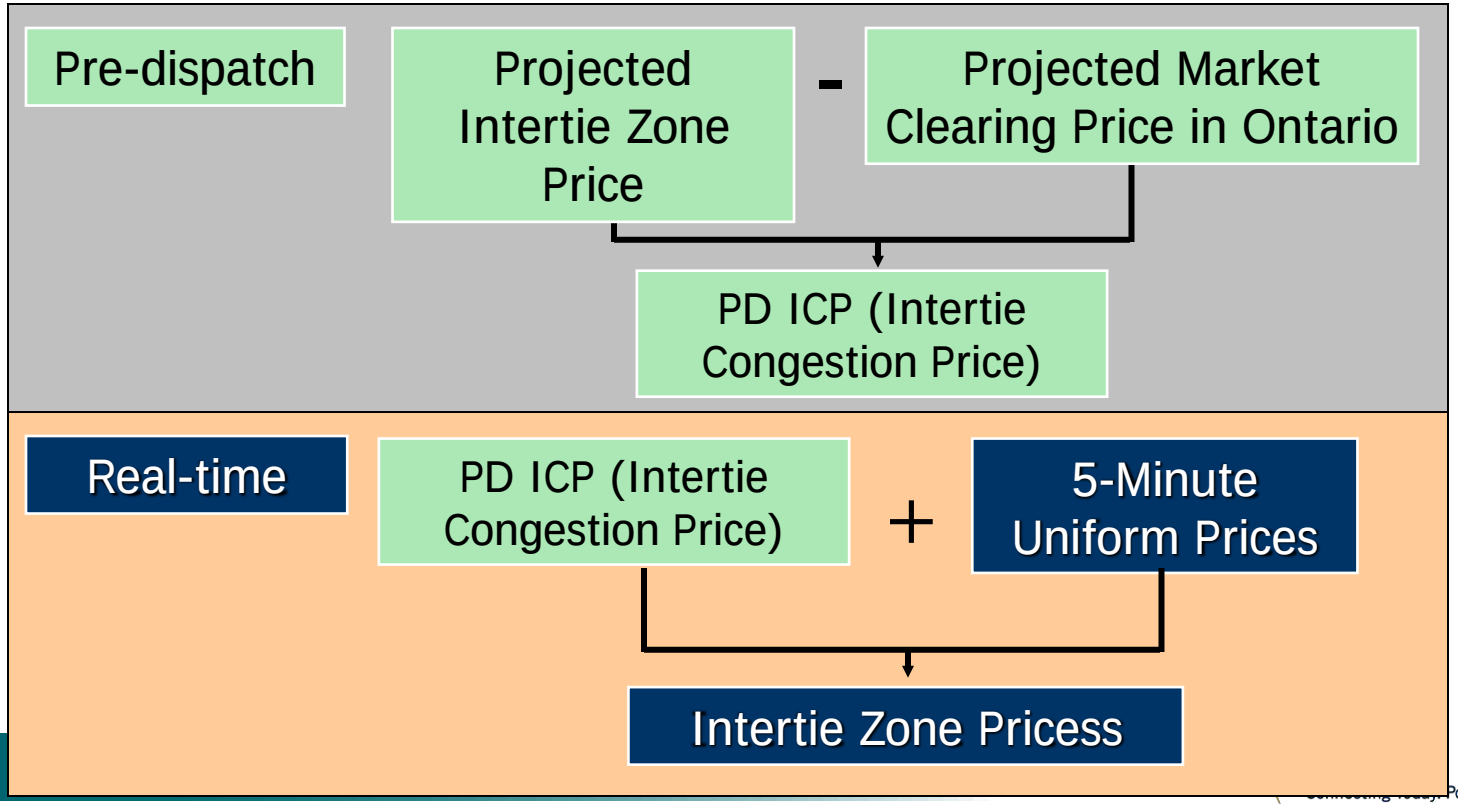
Renewed Market Single Schedule Design

One Schedule
(Constrained)

- Used to dispatch the system and determine prices (LMPs)
- Considers all relevant physical limitations of the system
- Much reduced need for out-of-market payments (Make Whole Payments)

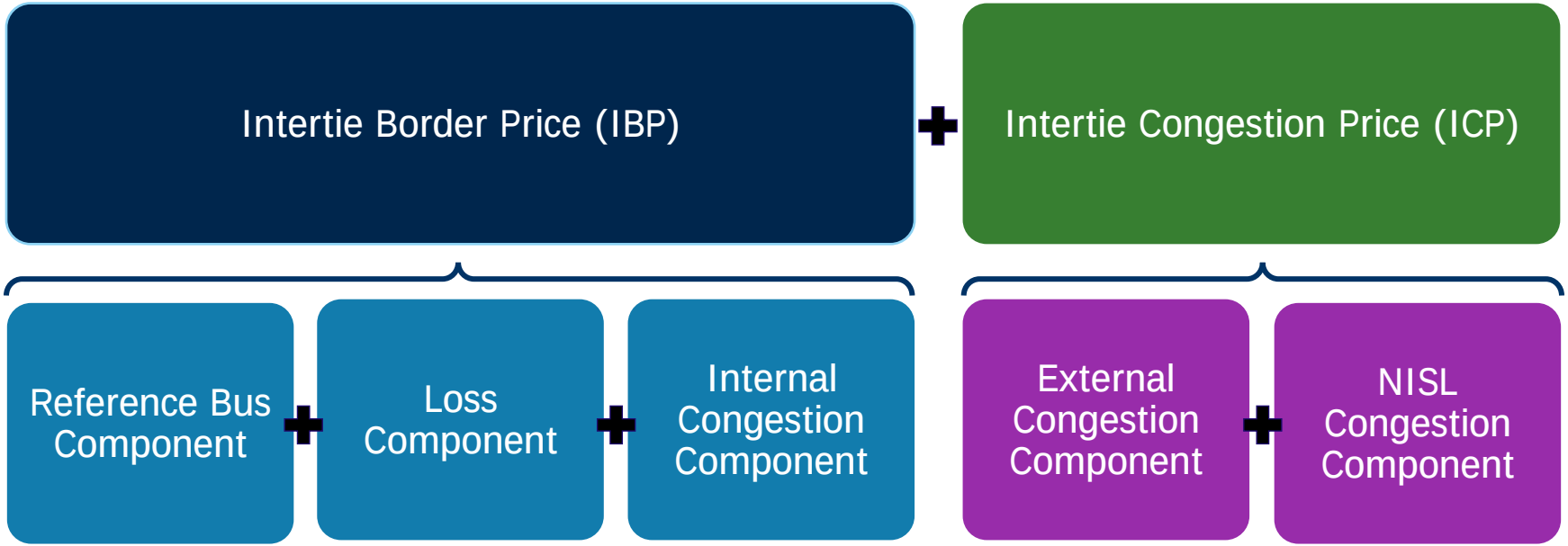
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Current Settlement Price Setting for Intertie Transactions



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Intertie LMP Components



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Renewed Market Real-Time Price Setting

- Real-time will have dynamic intertie settlement pricing. The exact approach will depend on the whether the intertie was congested or not in the final pre-dispatch run:

Congestion	Price Calculation
No congestion	The real-time intertie border price will be used
Export congested	The sum of the five-minute real-time intertie border prices and the pre-dispatch intertie congestion price
Import congested	The lesser of the pre-dispatch intertie LMP (IBP + ICP) or the five-minute real-time intertie border prices

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Changes to IESO Reports

- IESO reports can help you understand prices, system conditions and your resource's operations (for active market participants)
- All reports added, discontinued or changed are identified in documents available on the MRP Technical Reference Materials page of the IESO website (IESO.ca)
- Sample files, schemas and help files that detail the changes to each report and allow participants to test downstream processing of these reports are also available on that page

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Market Registration

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Market Registration for Intertie Traders

- Very little is new for intertie traders

Parameter	Discussion
Market Control Entity	This is any entity (registered on its own with the IESO or not) that has the ability to control or influence the participant's bids, offers or schedules in the day-ahead and/or real-time market through, e.g., an ownership, controlling, subsidiary or beneficiary relationship (see Market Rules Chapter 7, section 22.9 for details)

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Day-Ahead Market

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Day-Ahead Market and Intertie Trading

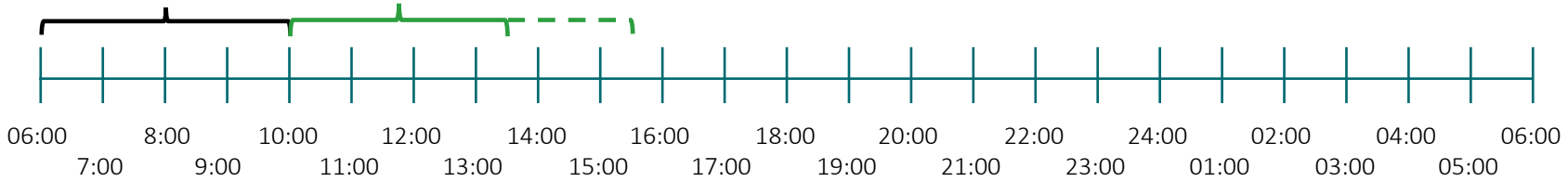
- The Day-Ahead Market (DAM) will provide financially binding day-ahead schedules for all classes of intertie transactions
- The Day-Ahead Intertie Offer Guarantee (DA-IOG) will not be required in the renewed market since the DAM will settle day-ahead scheduled imports at the day-ahead settlement price. As such, these transactions are inherently compensated at the day-ahead price without the need for an additional guarantee

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DAM Daily and Hourly Dispatch Data Submission

Unrestricted submission of both hourly and daily dispatch data for the next DAM run from 6:00 to 10:00 EPT. Standing dispatch data automatically entered at 6:00 EPT

New submissions or changes to hourly or daily dispatch data need IESO approval between 10:00 EPT and DAM result publication (13:30 EPT to 15:30 EPT).



- DAM timelines will be in Eastern Prevailing Time (EPT). All offers and schedules are in Eastern Standard Time (EST)

Note: Timeline as shown assumes EPT = EST

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Pre-Dispatch

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DAM Inputs to the PD Calculation Engine



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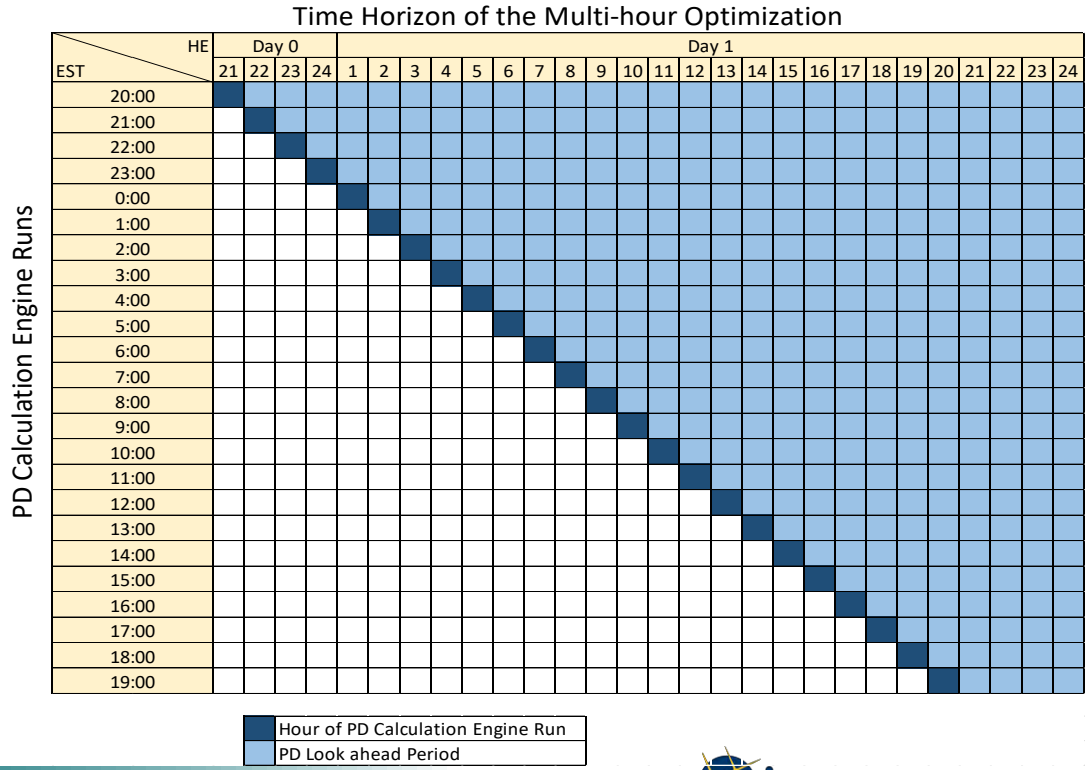
Overview: PD Calculation Engine Optimization

- In terms of intertie transactions, the pre-dispatch calculation engine will execute one pass to, among other things:
  - Produce next hour import/export dispatch schedules
  - Produce hourly advisory schedules and prices

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Pre-Dispatch Scheduling Timing – Renewed Market

- First run that looks out to tomorrow will start at 20:00 EST
- This is a change from now when the first run that looks out to tomorrow starts at 15:00 EST



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DAM Boundaries in Pre-Dispatch



	DAM	PD starts	HE22	HE23	HE24	HE1	HE2	HE3	HE4	HE5	HE6	HE7	HE8	HE9	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24
00	10:00 - 13:30	20:00	21:00	22:00	23:00	0:00	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00

- Pre-dispatch will schedule within the limits of the DAM schedules in all hours more than two hours in the future; i.e., during this period the algorithm can schedule the same, less, or none of each DAM-scheduled intertie transaction, but not more
- Pre-dispatch will not consider intertie transactions submitted but not scheduled in the DAM, or which were submitted after the DAM, for any hour more than two hours ahead

Real-time

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Pre-Dispatch Inputs to the Real-time Calculation Engine



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Real-time

- The real-time calculation will be a constrained pricing and scheduling run every five minutes
- Intertie transactions scheduled in the last pre-dispatch prior to the start of the hour, and which were confirmed during checkout, are treated as fixed supply or demand for the hour
- Intertie transactions may be curtailed during the hour for adequacy or security reasons or due to intertie outages. If so, they can be afforded a make-whole payment

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Linked Wheel-Throughs

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Linked Wheel-Through Transactions

- Linked wheel-through transactions occur when a market participant submits an import offer and an export bid on different interfaces in the same hour in a manner which indicates that they want the IESO to schedule them to the same MW quantity
- Linked transactions are limited to the lower of the two quantities scheduled; e.g., if the export would be scheduled on its interface to less than what the import would be scheduled to on its interface, the import is lowered to match the export quantity

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Linked Wheel-Through Transactions

- Currently
  - Import and export legs are assessed day-ahead as linked transactions
  - Pre-dispatch assesses both as separate transactions
- Renewed market
  - Both the DAM and pre-dispatch will assess the import and export legs as linked transactions

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Identifying Linked Wheel-Throughs

- MPs enter a valid NERC tag when submitting an intertie transaction
- If an MP wants an import and export to be linked, they will:
  - Prefix the import NERC tag with ‘WI
  - Prefix the export NERC tag with WX
  - Use the same e-tag ID for both legs
- Unlike currently, there will be no special requirements for wheel-through offer/bid prices – MPs will be free to enter prices as wished (within normal bid/offer price limits)

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Operating Reserve

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Operating Reserve

- Operating reserve (OR) is supply or demand reduction the IESO can call on within 10 or 30 minutes to help balance supply with demand until requirements can again be met through regular dispatch
  - Exports can supply 10-minute non-spinning or 30-minute reserve where the IESO has the agreement of the neighbouring control area that these transactions can be treated as OR

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Operating Reserve Scheduling

- Dispatch data submission timelines are the same as for energy
- The DAM will produce financially binding schedules for operating reserve
- Pre-dispatch can create additional operating reserve schedules, which will be advisory for all look-ahead hours past the next hour
  - Resources scheduled by pre-dispatch will be settled at the real-time prices for the applicable Reserve Area

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Renewed Market OR Intertie Price Setting

Intertie OR Price = RAORP + External Congestion

Where:

Reserve Area OR Price (RAORP) is the price of OR in the Operating Reserve Area in which the Ontario side of the interface is located

RAORP = OR Ref Price + OR Congestion Price

External Congestion is the congestion between the external zone and the Ontario zone when intertie limits are binding

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Ex-Post Market Power Mitigation

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What is Market Power?

- A market thrives when there is open competition among many market participants
- When competition is restricted, market participants have the ability to raise prices and to maintain them above the level that would prevail under competition
- This can lead to inefficient market outcomes and increased costs for consumers
- Market Power Mitigation (MPM) refers to actions taken to prevent market participants from exercising market power

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Ex-Post Mitigation for Economic Withholding

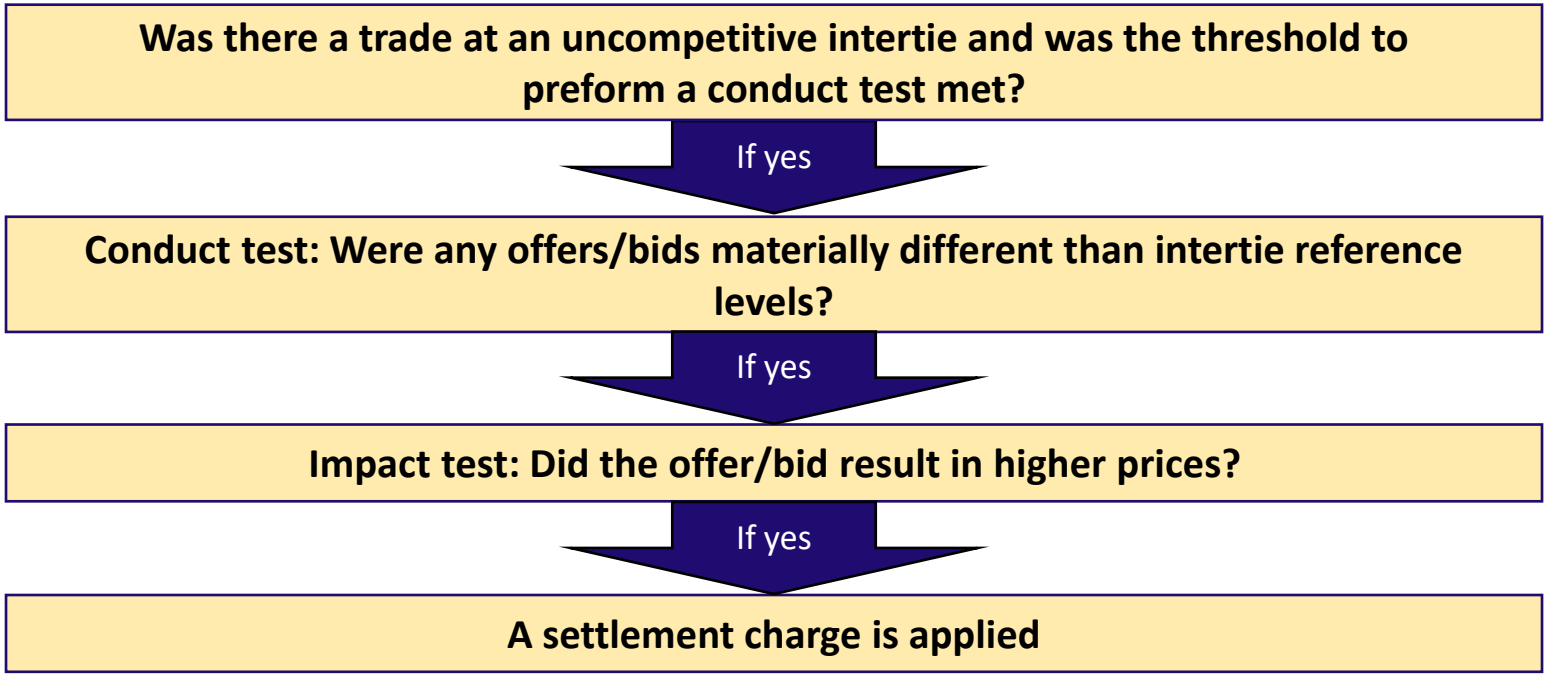
- After the dispatch day (i.e., ex-post) an assessment determines if there was economic withholding of energy or operating reserve at interties designated as uncompetitive
- An intertie zone will be designated as uncompetitive if:
  - One MP was scheduled in the DAM for at least 90% of the imports or exports in the previous calendar quarter, and/or
  - The IESO reasonably determines that effective competition in the intertie zone is, or is expected to be, restricted

Intertie Reference Levels

- Reference levels (prices) will be established for boundary entity resources at uncompetitive interties. These will be an estimate of the price for energy or operating reserve that the MP would have offered or bid if competition had not been restricted
- Daily DAM and real-time market intertie reference levels (IRLs) will be determined for each MP for each boundary entity resource using information available 14 days following the relevant dispatch day

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Overview of Ex-Post MPM for Intertie Transactions



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Evaluation of Exports

- The IESO will only assess an export transaction if the energy trader disclosed a market control entity that was also designated as the market control entity for physical withholding for a dispatchable resource that is authorized to supply energy or operating reserve

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Ex-Post MPM at Uncompetitive Interties – MWP

- Economic withholding can also effect make-whole payments. The IESO may assess make-whole payments made on transactions in uncompetitive intertie zones if:
  - The boundary entity resource boundary entity resource was tested for an energy or operating reserve price impact; or
  - The boundary entity resource boundary entity resource was scheduled to provide operating reserve and received a make-whole payment greater than $10,000 for a dispatch hour

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Settlements Overview

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Two-Settlement Mechanics – Energy

	Day-Ahead		Real-Time (Balancing)
	$Quantity_{DA}$ x Intertie LMP_{DA}	+	($Quantity_{RT}$ – $Quantity_{DA}$) x Intertie LMP_{RT}
Exports	Pay for day-ahead scheduled withdrawals		• Pay for incremental real-time withdrawals • Are credited for unconsumed day-ahead scheduled withdrawals (sell-back)
Imports	Are paid for day-ahead scheduled injections		• Are paid for incremental real-time injections • Pay for undelivered day-ahead scheduled injections (buy-back)

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Two-Settlement Energy Import Example

Day-Ahead		Real-Time (Balancing)
$Q_{DA} \times LMP_{DA}$	+	$(Q_{RT} - Q_{DA}) \times LMP_{RT}$
DAM schedule: 150 MW DAM price: $25		Actual schedule: 100 MW Real-time price: $30
$Q_{DA} \times LMP_{DA}$ = 150 MW x $25 = $3,750 payment		$(Q_{RT} - Q_{DA}) \times LMP_{RT}$ = (100 MW – 150 MW) x $30 = -$1,500

Import must buy back undelivered DAM MWs at the real-time locational marginal price

Net Energy Settlement = $2,250 payment

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Two-Settlement Energy Export Example

Day-Ahead		Real-Time (Balancing)
$Q_{DA} \times LMP_{DA}$	+	$(Q_{RT} - Q_{DA}) \times LMP_{RT}$
DAM schedule: 150 MW DAM price: $25		Actual consumption: 100 MW Real-time market price: $30
$Q_{DA} \times LMP_{DA}$ = 150 MW x $25 = $3,750 charge		$(Q_{RT} - Q_{DA}) \times LMP_{RT}$ = (100 MW – 150 MW) x $30 = -$1,500

Sells back unconsumed DAM scheduled MWs at the real-time locational marginal price

Net Energy Settlement = $2,250

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Two-Settlement – Operating Reserve

Day Ahead		Real-Time (Balancing)
$Quantity_{DA} \times OR_LMP_{DA}$	+	$(Quantity_{RT} - Quantity_{DA}) \times OR_LMP_{RT}$

Q_{DA} = day-ahead market operating reserve scheduled quantities

Q_{RT} = real-time market actual operating reserve quantities

OR_LMP_{DA} = day-ahead market locational marginal price of OR (hourly)

OR_LMP_{RT} = real-time market locational marginal price of OR (5-minute)

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Real-Time Intertie Offer Guarantee

- The real-time intertie offer guarantee (RT IOG) provides compensation to energy traders to reduce the price risk for imports due to differences in LMP between PD and RT and to ensure that they do not operate at a loss
- Imports scheduled in the DAM and RT for the same MW in the same hour and linked wheels are not eligible for a RT-IOG
- Real-time intertie offer guarantees are discussed in market manual 5.5: IESO-Administered Markets Settlement Amounts, section 2.18 and Appendix D where an example is provided

DAM Intertie Failure Charge

- An intertie failure charge will apply to day-ahead scheduled transactions which fail to flow in real-time for a reason within the MPs control:
  - The DAM failed MWs will be any MWs scheduled in the DAM and also scheduled by the last pre-dispatch before the start of the hour, but which do not flow in real-time
  - These MWs will be charged the real-time external congestion and real-time NISL costs

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Real-Time Intertie Failure Charges

- A Real-Time Intertie Failure Charge will apply to import and export transactions scheduled in last pre-dispatch before the dispatch hour (i.e., transactions which are incremental to any scheduled day-ahead) that fail to be scheduled in real-time due to a reason within the participant's control
  - The failure charge will be applied to the portion of the pre-dispatch schedule that is greater than the DAM schedule. A such, it will apply to the entire schedule if it was scheduled only in pre-dispatch

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Uplift

- In general terms, uplift is required to cover the additional costs necessary to operate an efficient market and a reliable grid
  - Some uplift can also be payments, since they can be used to distribute recovered amounts to consumers (loads and exports)
- A number of existing uplifts will be retired, and a number of new ones will be instituted to accommodate changes to the market
- While the particular set of uplift charges will change with MRP, they will continue to be recovered from loads and exports on a volumetric basis

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Charge Types

- A number of existing charge types will be fully retired. For example, congestion management settlement credit and Day-Ahead Commitment Process-related charge types will be retired
- A large number will be replaced with new charge types which reflect the renewed market design
- See the IESO Charge Types and Equations document for more information about charge types in the renewed market

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Transmission Rights Auction



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Transmission Rights Overview

- Transmission Rights (TRs) are financial instruments sold in auctions which currently provide the holder a payment based on the directional price differential between the Ontario zonal price and an intertie zone price
- TRs were instituted as part of the current market design to provide a way for intertie traders to hedge against the uncertainty of intertie congestion costs
- This was expected to increase intertie trade, helping to support the efficient and reliable operation of the market

Renewed Market TRs

- The renewed market design raises two key questions:
  1. There are now two schedules and prices – one set for the DAM and another set for the real-time market
     - Which should be the basis of TR settlement?
  2. The new intertie price methodology includes the impact of NISL
     - Should TRs be a hedge not just against intertie congestion on a particular path, but also against the total hourly change in intertie schedules across all interfaces?

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Basis for TR Settlement

- The DAM provides intertie traders the opportunity to hedge real-time congestion by locking in day-ahead prices. As such, TRs will not be needed to do this. Instead, TRs will best be used to hedge intertie congestion in the DAM
- The TR Market Review (available on the IESO website) concluded that it would not be appropriate for TRs to hedge NISL congestion costs because of the risks of TR market underfunding due to the potential for actions intended to maximize inter-hour ramping

Renewed Market TR Settlement

- TR settlement credits will be calculated as:
  - Export Congested
    - Max(0, $DAMQ_{TR}$ x DAM_{PEC} for injection TR zone)
  - Import Congested
    - Max(0, -1 x $DAMQ_{TR}$ x DAM_{PEC} for withdrawal TR zone)
- Any negative results are capped at $0. Transmission rights can only be a payment, not a charge.

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TR Payout Examples

- Assume the Michigan/Ontario interface is export congested in DAM:
  - Participant A holds 100 TRs on the MICH – ON path
  - Participant B holds 100 TRs on the ON – MICH path
  - DAM external congestion component is $10 indicating the intertie is export congested (external congestion less than zero indicates import congestion)

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TR Payout Example

- Participant A does not receive a payout since their TR hedges import congestion
- TR Payout = MAX(0, -1× $10 × 100)

  = -$1,000

  = $0 since TR payouts cannot be negative
- Participant B receives a payout since their TR hedges export congestion

  TR Payout = MAX(0,1× $10 × 100)

  = $1,000

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Virtual Traders



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Virtual Traders

- The two-settlement system will also allow for the sale and purchase of virtual transactions
- Virtual transactions allow registered virtual traders to bid/offer energy in the DAM, receive a schedule, be settled for that MW quantity at the day-ahead price, and be settled for the opposite transaction at the real-time price



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Price Convergence

- Virtual transactions will help convergence DAM and real-time prices
- Why is this important? Because converged prices improve market efficiency

If the Trader expects….	Trader will….	So they would have….	Convergence effect….
Day-ahead price to be lower that the real-time price	Buy at lower day-ahead price; be paid for the same quantity of MWs at higher real-time price	Bought low and sold high	Increases day-ahead demand; may increase day-ahead price towards higher real-time price
Day-ahead price to be higher than the real-time price	Sell at higher day-ahead price; be charged for the same quantity of MWs at the lower real-time price	Sold high and bought low	Adds to supply day-ahead; may reduce day-ahead price towards lower real-time price

Virtual Transaction Bid/Offer Locations

- Nine Virtual Trading Zones
- One source resource (for offers to sell energy) and one sink resource (for bids to buy energy) per Virtual Trading Zone; e.g., East Zone will have the EAST_BID:HUB and EAST_OFFER:HUB resources

Virtual Zone
East
Essa
Niagara
Northeast
Northwest
Ottawa
Southwest
Toronto
West

Determination of Zonal Prices

- The zonal prices used to settle virtual transactions are calculated as the average load-weighted locational marginal prices at all Ontario load points within the zone
- DAM and RT prices will be calculated and used for settlement. Pre-dispatch prices will also be determined, but will be provided for information purposes only

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Energy Settlement Charge Codes

Transaction	DAM Settlement	Real-Time Settlement
Sale day-ahead; purchase real-time	Charge Type 1106	Charge type 1107
Purchase day-ahead; sale real-time	Charge type 1108	Charge type 1109

- Charge Type 1852: Day-Ahead Market Reliability Scheduling Uplift – Virtual Transactions to Sell (DRSU) – Charged to DAM virtual sellers to cover a portion of the cost incurred if the DAM has to schedule additional physical resources in place of virtual supply to ensure sufficient energy availability during the next day's expected demand peak

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Final Preparations



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For More Information

- The IESO has released a series of eLearning Modules that stakeholders can access and complete on demand: MRP - eLearning Modules. These explain market-related processes from registration to settlement under the renewed market for nine different participant types, including:
  - Intertie Transactions and Transmission Rights Auction, and
  - Virtual Traders

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For More Information

- There are also various training guides available including:
  - Guide to Prices in the Renewed Market
  - Day-Ahead Market quick take
  - Introduction to Virtual Traders

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Market Rules and Market Manuals

- Market Rules are the basis for renewed market operations
- Market Manuals provide additional detail and Market Rule references
- All can be found here - Renewed Market Rules & Manuals Library

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Final Preparations

- Ensure your organization's registration data, contacts and permissions are up to date in Online IESO
- Submit Market Control Entities (MCEs) and MCE for Physical Withholding
- Review changes to reports on the Technical References page to see if any IESO reports your organization relies on are changing (e.g., pricing or settlement reports)
- Prepare for the cutover to the renewed market and systems MRP-Readiness-Plan-for-Market-Renewal-Launch.pdf

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Final Preparations

- You can also attend an upcoming webinar:
  - An April 16 webinar will be held focusing on final preparations for the launch of the renewed market and what to expect during the cutover
- More information available on the Market Participant Readiness page
- If you have questions, contact us at customer.relations@ieso.ca

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Thank You



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Exhibit “V”

IESO Interjurisdictional Energy Trading training guide dated May 2025

Exhibit “V”

to the Affidavit of Robin Doolittle

Sworn before me on October 29, 2025, in accordance with O. Reg. 431/20,
Administering Oath or Declaration Remotely



Commissioner for Taking Affidavits
(or as may be)

October 29, 2025

Keith Edward Hickey, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.

Expires June 24, 2027.

A1587

Interjurisdictional Energy Trading

IESO Training

May 2025

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AN IESO MARKETPLACE TRAINING PUBLICATION

This guide has been prepared to assist in the IESO training of market participants and has been compiled from extracts from the market rules or documents posted on the web site of Ontario's Independent Electricity System Operator. Users of this guide are reminded that they remain responsible for complying with all of their obligations under the market rules and associated policies, standards and procedures relating to the subject matter of this guide, even if such obligations are not specifically referred to herein. While every effort has been made to ensure the provisions of this guide are accurate and up to date, users must be aware that the specific provisions of the market rules or particular document shall govern.

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1. Introduction

The IESO-controlled grid is connected to five neighbouring jurisdictions with intertie transmission lines. These lines allow Ontario to import and export energy. This workbook introduces the basic concepts of Interjurisdictional Energy Trading (IJT) in the IESO-administered markets.

Note: This workbook does not include detailed information on interjurisdictional energy trading under the Day-Ahead Market (DAM). For information on the DAM, please refer to:

Market Manual 0.4.2 concerning the Operation of the Day-Ahead Market, available on the Market Rules and Manuals Library web page.

1.1 Prerequisite

To benefit from this module, users need an understanding of how Ontario's physical markets work. This knowledge can be gained by reading the Introduction to Ontario's Physical Markets workbook, available on the Training home page.

Objectives

After completing this workbook users will be able to:

- Identify the markets in which importers and exports can participate
- List the three types of import/export transactions and relate them to transactions within Ontario
- Distinguish between Ontario prices and prices used for imports and exports
- Identify the impact imports and exports have on Ontario prices
- Explain how prices are set for imports and exports
- Recall how imports and exports are scheduled
- Calculate intertie offer guarantee (IOG) payments
- Explain the application of the net interchange schedule limit
- Discuss the settlements process and associated charge types
- Explain schedule compliance requirements and potential failure charges

2. Interjurisdictional Energy Transactions

Moving energy across intertie transmission lines to or from other control areas is referred to as interjurisdictional energy trading (IJT). Market Participants (MP's) wishing to conduct IJT can participate in both the real-time energy and operating reserve markets in Ontario. While interjurisdictional transactions are similar to transactions within Ontario, there are significant differences. These differences will be explained in this workbook.

Objectives

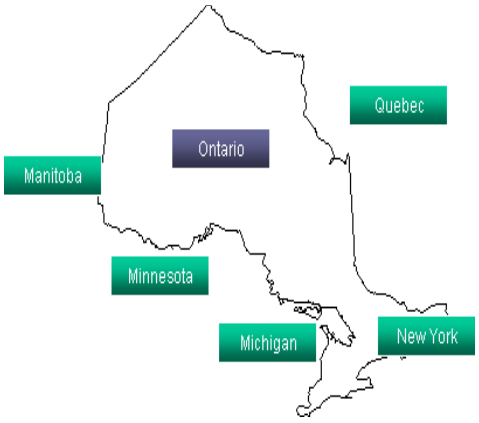
When users have completed this section, they will be able to:

- List the adjacent control areas available for interjurisdictional trade
- Explain the types of interjurisdictional transactions
- Identify when interchange schedules are determined and explain why this is different from when schedules for facilities within Ontario are set

2.1 Interties

Ontario is interconnected with five other jurisdictions (or "control areas"):

- Manitoba
- Minnesota
- Michigan
- New York
- Quebec



Interties are transmission lines that allow energy to move between adjacent balancing authorities. Like any transmission line, interties can carry only so much energy. Exceeding this level can result in reliability issues such as overheating.

Ontario's IESO and our interconnected partners work together to keep flows across the interties within these limits. Intertie flows are also managed by the IESO to ensure the stable operation of the electricity grid within Ontario.

2.2 Types of Interjurisdictional Energy Trading

There are three types of interjurisdictional energy transactions. A participant can:

- Import energy or operating reserve from another control area into Ontario
- Export energy from Ontario to another control area
- Move energy from one jurisdiction, through Ontario, to a different jurisdiction (called “wheeling” or a “Wheel-Through)



In order for an intertie transaction scheduled in Ontario to flow, there must be a matching transaction scheduled in a neighbouring jurisdiction. For example, an import from New York scheduled in the Ontario market must have a matching export scheduled in the New York market. It is the responsibility of the MP to ensure that appropriate matching transactions are scheduled by meeting the requirements of the neighbouring jurisdiction.

2.2.1 Import

An import involves moving energy from another control area into Ontario for use by consumers within Ontario. An import acts much like an internal generator in that it helps meet Ontario energy demand. As with internal generators, a participant wishing to complete an import transaction must make a supply offer in the IESO-administered market. Import offers are considered along with all other offers received from suppliers. An import offer is accepted and scheduled if:

- It is required to meet demand,
- It is economic in comparison to other supply, and
- It can be physically accommodated by the intertie and the IESO-controlled grid.

2.2.2 Export

Exports are treated in much the same way as internal dispatchable load. In order to export energy, an MP must place a bid in the IESO-administered market to purchase energy at the intertie. An export will be scheduled if the bid is economic, and the intertie and IESO-controlled grid can physically accommodate the transaction.

2.2.3 Wheel-Through

A wheel-through[1] allows an MP to move energy from one jurisdiction through Ontario to another jurisdiction. For example, an MP may want to move energy from New York to Minnesota through Ontario. This movement is achieved by transacting both an import to Ontario and an export from Ontario during the same period.

[1] For more information regarding wheeled transaction, refer to Market Manual 4.1: Submitting Dispatch Data in the Physical Markets, Section 4.2.

In the simplest form of wheel-through, an MP makes an offer to import energy and a bid to export energy during the same period. If both the bid and offer are accepted, the energy will flow into and out of Ontario at the same time. Importantly, in this form of wheel-through the two transactions (import and export) are totally independent from each other. The success of one transaction has no influence on the success of the other. Therefore, if one leg fails, the other may still flow. This may present a risk to the MP.

This risk can be avoided by "linking" the two legs of the wheel-through. This ensures that if one leg of a wheel-through is curtailed or fails, the other leg will also be curtailed.

Linking a wheel-through is achieved by submitting the NERC tags for each leg in a particular format (see the example below)[2]

Below is an example of a linked wheel intended from Michigan to Quebec. In the first scenario, the prefixes were not added to the e-Tag IDs for the import and export transactions and the engine evaluated the transactions separately, scheduling them to different quantities. In the second scenario, the WI and WX prefixes were included in the e-Tag IDs and the engine scheduled the transactions to the same quantity.

Scenario	Leg	e-Tag ID Submitted	Offer / Bid	Schedule	Outcome
e-Tag ID and prefix requirements not met	Import	MECS_ONTMM1234_HQT	120	100	• Transactions not considered as a linked wheel by the DAM and PD engines • Import and export legs may be scheduled to different quantities
	Export	MECS_ONTMM12345_HQT	120	110	
e-Tag ID and prefix requirements met	Import	**WI_MECS_ONTMM1234_HQT**	120	100	• Transactions considered as a linked wheel by the DAM and PD engines • Import and export legs scheduled to the same quantity
	Export	**WX_MECS_ONTMM1234_HQT**	120	100	

2.2.4 Operating Reserve

Operating Reserve (OR) is stand-by power or demand reduction that the IESO must have available in case of a contingency on the grid such as the loss of a generator. If a contingency occurs, OR is activated, re-establishing the balance between supply and demand and thereby maintaining system reliability. The IESO purchases OR on behalf of the market. The cost is then charged back to loads (including exports) through an uplift.

MP's involved in imports and exports can offer 10-minute non-spinning and 30-minute operating reserve. In order to offer OR an MP must:

- Be able to provide the energy when called upon within the time frame specified by the class of operating reserve involved (either 10 minutes or 30 minutes)
- Be able to supply the energy for up to one hour (the neighbouring jurisdiction must allow this to occur)

[2] Please see Market Manual 4.1: Submitting Dispatch Data in the Physical Markets on the Market Rules and Manuals Library web pages for more details on wheel-throughs

- Have a bid or offer in the energy market for an amount greater than or equal to the quantity of your operating reserve offer

2.2.5 Capacity Backed Exports

Ontario-based generation resources as well as the injecting component of electricity storage resources may be eligible, subject to IESO pre-approval, to export capacity to designated external control areas during specified periods of time (refer to Market Rules Chapter 7: System Operations and Physical Markets, Section 20). Resources which have been approved for export may at times be "called" by the jurisdiction into which it has sold its capacity. An external jurisdiction may call on capacity exports when they are experiencing or anticipate experiencing an operating reserve or energy shortfall. Called exports are required to export energy to the calling jurisdiction for a specific period of time in a specified amount.

Bids[3] for called capacity exports will need to have the Capacity Transaction Flag dispatch parameter set to "Yes" for each dispatch hour for which the bid is submitted. Unlike most other export transactions, the IESO will assess a capacity backed export in all PD runs regardless of whether it was offered in the DAM or not.

[3] For detailed information regarding capacity transactions, refer to Market Manual 4.1: Submitting Dispatch Data in the Physical Markets, Section 4.3.

3. Placing Bids and Offers

Placing an offer or bid at an intertie is very similar to placing one within Ontario:

- Bids and offers are placed using the Energy Market Graphical User Interface (EMI) Workspace.[4]
- No physical transmission rights are required. Once a transaction is scheduled, the MP has access to Ontario's transmission system.

Objectives

When users have completed this section they will be able to:

- List the offer/bid information requirements for interjurisdictional trade
- Explain the concept of a boundary entity

There are two primary differences, however, between bids and offers within Ontario and those at the interties:

- An MP bidding or offering in Ontario must indicate the location of the desired transaction (i.e., where the energy will either be injected into or taken out of the IESO-controlled grid). This information is required by the IESO calculation engine so it can evaluate the effects of any physical system constraints when considering the transaction. Knowing the location of the transaction is also critical information for settlement purposes. An MP indicates it's transaction's location by entering a resource name with their bid or offer. A resource name is a unique identifying reference which is associated with a facility (e.g., a generator or load).
- With intertie transactions, the IESO needs to know where the energy is going to (if an export) or coming from (if an import). However, intertie bids and offers are not associated with a facility registered within Ontario. Therefore, a boundary entity resource is used to indicate an intertie transaction's location.[5] In addition to the resource, the participant must also indicate which intertie they plan to use.

[4] Please see the "Submitting, Revising and Cancelling" series of Training Guides available on the Participant Tool Training web page for more information on entering, revising and cancelling offers and bids.

[5] Please see Market Manual 4.1: Submitting Dispatch Data in the Physical Markets on the Market Rules and Manuals Library web page for a complete listing of boundary entity resources.

- The MP must enter a NERC tag with their export bid or import offer.[6] Participants are responsible for updating the tag if the quantity of energy that clears the market is different from the quantity indicated in the originally submitted NERC tag (see the next section for timing).[7] The Ontario portion of the transaction should be designated as FIRM "7F". Quebec transactions should use the control area HQT.

Summary

MP's who wish to import energy must make an offer to inject into the IESO-controlled grid. An import offer is placed using the EMI interface or an available API in much the same way as a generator in Ontario places an offer.

MP's who wish to export energy must make a bid to withdraw energy from the IESO-controlled grid. An energy bid is placed using the EMI in much the same way as a dispatchable load in Ontario places a bid.

Import offers and export bids are evaluated by the calculation engines, taking into consideration both the economic competitiveness of the bid or offer, and the physical ability of the intertie and of the IESO-controlled grid to accommodate the transaction.

[6] NERC (North American Electric Reliability Corporation) tags are participant-selected codes that identify intertie transactions. For more information on NERC Tags, please see the NERC web site: www.nerc.com and Market Manual 4.1: Submitting Dispatch Data in the Physical Markets on the Market Rules and Manuals Library web page web page.

[7] Except for transactions with New York, where the sink balancing authority will make any required changes for you. Please see Market Manual 4.1: Submitting Dispatch Data in the Physical Markets on the Market Rules and Manuals Library web page.

4. Skill Check One

1. What are interties and why are they important for Ontario's electricity grid? (Select the correct answer)
   a) Interties are power plants within Ontario that generate electricity
   b) Interties are transmission lines that allow energy to move between adjacent balancing authorities
   c) Interties are storage facilities for excess energy
   d) Interties are financial instruments used in energy trading

2. An import offer is accepted and scheduled if it is required to meet demand, is economic in comparison to other supply, and can be physically accommodated by the intertie and the IESO-controlled grid. (Select True or False)
   a) True
   b) False

3. What are the three types of interjurisdictional energy transactions that can occur in Ontario? (Select the correct answer)
   a) Import, Export, and Storage
   b) Generation, Distribution, and Consumption
   c) Import, Export, and Wheeling (Wheel-Through)
   d) Transmission, Distribution, and Retail

4. What is Operating Reserve (OR) and what are the requirements for an MP to offer OR? (Select the correct answer)
   a) OR is excess energy stored for future use; MPs must have storage facilities
   b) OR is stand-by power or demand reduction; MPs must be able to provide energy within the specified time frame, supply energy for up to one hour, and have a bid or offer in the energy market
   c) OR is energy imported from other jurisdictions; MPs must have import agreements
   d) OR is energy exported to other jurisdictions; MPs must have export agreements

5. A boundary entity resource is used to indicate the location of an intertie transaction because intertie bids and offers are not associated with a facility registered within Ontario. (Select True or False)

   a) True

   b) False

4.1 Skill Check One Answers

1. What are interties and why are they important for Ontario's electricity grid? (Select the correct answer)

   a) Interties are power plants within Ontario that generate electricity

   b) Interties are transmission lines that allow energy to move between adjacent balancing authorities

   c) Interties are storage facilities for excess energy

   d) Interties are financial instruments used in energy trading

2. An import offer is accepted and scheduled if it is required to meet demand, is economic in comparison to other supply, and can be physically accommodated by the intertie and the IESO-controlled grid. (Select True or False)

   a) True

   b) False

3. What are the three types of interjurisdictional energy transactions that can occur in Ontario? (Select the correct answer)

   a) Import, Export, and Storage

   b) Generation, Distribution, and Consumption

   c) Import, Export, and Wheeling (Wheel-Through)

   d) Transmission, Distribution, and Retail

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   b) OR is stand-by power or demand reduction; MPs must be able to provide energy within the specified time frame, supply energy for up to one hour, and have a bid or offer in the energy market

   c) OR is energy imported from other jurisdictions; MPs must have import agreements

   d) OR is energy exported to other jurisdictions; MPs must have export agreements

5. A boundary entity resource is used to indicate the location of an intertie transaction because intertie bids and offers are not associated with a facility registered within Ontario. (Select True or False)

   a) True

   b) False

5. Intertie Scheduling

The IESO uses three calculation engines (DAM. PD and RTM) to determine prices and schedules[8] that run in three timeframes:

- Daily in the "Day-Ahead Market" to produce financially binding day-ahead schedules for all hours of the next day for all dispatchable, self-scheduling and intermittent resources. This includes producing energy and OR (10NS and 30R) schedules for imports and exports.
- Hourly in "pre-dispatch" to determine projected prices, projected schedules for dispatchable facilities within Ontario, and projected and actual interchange schedules
- Every five minutes in "real-time" to determine actual dispatch schedules for facilities within Ontario, and settlement prices.

Objectives

When users have completed this section they will be able to:

- Explain the offer/bid information requirements for interjurisdictional trade, including the necessary details and submission deadlines.
- Identify the relevant IESO resources for obtaining information about intertie scheduling, including the IESO Reports site and Market Rules.
- Explain how intertie transactions are scheduled in the Day-Ahead Market (DAM), pre-dispatch (PD), and real-time (RT) timeframes.
- Recognize the exceptions to the normal intertie scheduling process, such as those related to capacity obligations, emergency energy transactions, and reliability management.

MP's with dispatchable facilities in Ontario receive dispatch instructions every five minutes. Dispatch instructions tell the participant what quantity of energy they should be injecting or withdrawing by the end of the five-minute interval during which the instruction was received.

The IESO cannot issue dispatch instructions every five minutes in real-time to facilities located outside of Ontario. Instead, interjurisdictional trade is co-ordinated between the IESO and other balancing authorities, using hourly interchange schedules. Imports and exports are scheduled on an economic basis within the physical security limits of the intertie and of the IESO-controlled grid.

[8] See the Introduction to Ontario's Physical Markets workbook available on the Training web page.

Which imports or exports are accepted for a particular dispatch hour is determined by the pre-dispatch calculation engine run during the preceding hour (for example, the schedule for 12:00 to 13:00 is determined between 11:00 and 12:00). This schedule is then confirmed with IESO's neighbouring jurisdictions to determine if matching transactions have been scheduled. Once this is confirmed, transactions become fixed for the dispatch hour. This means that they do not change during the hour (unless a change is needed for reliability reasons). Further, no additional intertie transactions can be made to flow during the hour using market mechanisms.

Therefore, intertie transactions compete economically in both the DAM and in pre-dispatch in order to be scheduled, but are then fixed for the hour in real-time. This has an important effect on pricing and settlements, which will be explained in later sections.

MP's use the IESO Reports site to retrieve their interchange schedules before the dispatch hour. For example, the interchange schedule for the hour starting at 9:00 eastern standard time (EST) is determined by a run of the IESO algorithm during the previous hour. This interchange schedule should be available by 8:20 Participants are required to supply valid NERC tags at least 30 minutes prior to the dispatch hour (35 minutes if Transmission Load Relief (TLR) has been declared).

5.1 DAM Scheduling

The DAM calculation engine runs once per day to produce financially binding day-ahead schedules for all hours of the next day for all dispatchable, self-scheduling and intermittent resources. This includes producing energy and OR (10NS and 30R) schedules for imports and exports. Bids and offers must be submitted between 6:00 and 10:00 Eastern Prevailing Time (EPT)[9] to be considered in the DAM, which begins its run at 10:00 EPT. Standing bids and offers will be automatically entered into the DAM at 6:00 EPT. The DAM will normally complete its run at 13:30 EPT, although it may be delayed as late as 15:30 EPT.

5.2 PD Scheduling

Actual Ontario supply and demand in real-time can differ from day-ahead forecasts due to a number of factors. As a result, the PD calculation engine is used to transition from day-ahead to real-time operations. The PD calculation engine run which starts at 20:00 Eastern Standard Time (EST) produces look-ahead schedules and prices for each of the remaining hours of the day and all hours of the next day. PD is run hourly thereafter with each run's look-ahead period reducing by one hour until 20:00 EST the next day, at which point the cycle repeats.

The PD calculation engine receives information from the DAM, including offers and bids and day-ahead import and export schedules. Intertie transaction offers and bids can also be submitted without IESO approval after the close of the DAM submission window up to the start of the mandatory window, two hours before the dispatch hour.

[9] Eastern Prevailing Time (EPT) means the current time applicable in Ontario, whether Eastern Standard Time or Eastern Daylight Savings Time.

The PD calculation engine which initiates in any given hour (let's call it Hour T) will evaluate and schedule both DAM-scheduled and non-DAM-scheduled intertie transactions for Hours T+1 and T+2 of the PD run look-ahead period. For all hours beyond T+2, the PD calculation engine will normally only evaluate DAM-scheduled intertie transactions, up to the MW quantity of the DAM schedule. Exceptions include:

- The intertie transaction is associated with a capacity obligation,
- If it is an emergency energy transaction, or
- As otherwise allowed by the IESO, such as:
- In response to a DAM failure,
- To manage overall reliability of the system, or
- To manage surplus conditions.

Intertie schedules for the next hour are determined by pre-dispatch (so for Hour T+1) and will represent the schedules for actual intertie operations for the next hour, subject to any changes resulting from formal checkout procedures with our neighbouring jurisdictions.

5.3 RT Scheduling

The RT calculation engine10 will perform multi-interval optimization to determine real-time dispatch for internal Ontario resources for the next five-minute dispatch interval and advisory dispatches for the subsequent ten five-minute intervals. The engine considers resource and system constraints to determine dispatch schedules and real-time LMPs.

The schedules for imports and exports are held fixed by the RT calculation engine as determined by the PD calculation engine and as confirmed during checkout unless reliability-related curtailments are made during the hour.

[10] For more information regarding the PD and RT scheduling process, refer to Market Manual 4.3: Operation of the Real-Time Market, Section 2 and 3 respectively.

6. Pricing and Scheduling of Interjurisdictional Trade

Imports are paid the price in the zone through which they are importing while exports pay the price in the zone through which they are exporting. Intertie zone prices may be higher, lower, or the same as the price used to settle transactions occurring in the Ontario zone. Differences between the Ontario and intertie zone prices are caused by congestion.

Objectives

When users have completed this section, they will be able to:

- Define “intertie congestion price” (ICP)
- Analyze intertie prices with and without congestion
- Recognize the impact of NISL on intertie prices and market dynamics
- Understand how scheduling imports and exports an hour ahead affects intertie prices

The calculation engines determine prices for Ontario as well as for a number of intertie zones:

Control Area	Code(s)
Ontario	ONZN
Manitoba	MBSI
Minnesota	MNSI
Michigan	MISI
New York	NYSI
Quebec	PQBE
	PQDA
	PQDZ
	PQHA
	PQHZ
	PQPC

	PQQC
	PQXY
	PQAT

Imports are paid the price in the intertie zone while exports pay the price in the zone. As with any transmission line, the interties that connect Ontario to neighbouring control areas have a maximum allowable flow limit. Scheduling transactions in excess of this limit can result in reliability issues, such as overheating. A maximum flow limit can be referred to as a “constraint” as it constrains the ability of the calculation engine to schedule transactions. Because of these flow limits, there can be more energy trying to move in a given direction across an intertie than can be physically accommodated. When this occurs, the calculation engine may not be able to schedule all the transactions that have an economic bid or offer. Instead, because energy can only be scheduled up to the maximum flow limit, energy that is otherwise economic may be left unscheduled. When this occurs the “constraint” is said to be “binding” due to congestion. A binding intertie constraint impacts both scheduling and pricing.

Intertie Locational Marginal Prices (LMP) will be made up of the Intertie Border Price (IBP) plus the Intertie Congestion Price (ICP). This LMP includes costs associated with internal congestion and losses, external congestion, and the Net Interchange Scheduling Limit (NISL) as shown in the equation:

$$\text{Intertie LMP} = \text{IBP} + \text{ICP}$$

Where:

Intertie Border Price (IBP) is the LMP at the Ontario side of an interface.[11]

IBP = Reference Bus Component + Loss Component (reference bus to the border) + Internal Congestion Component (reference bus to the border).

Reference Bus Component is the cost of serving one additional increment of demand above actual demand at a specific location on the grid known as the ‘Reference Location’.

Loss Component which reflects the impact on system losses of serving an additional increment of demand at a pricing location with supply from the reference bus.

Internal Congestion Component which reflects the cost impact of relaxing each system constraint in turn between the Reference Bus and the pricing location.

Intertie Congestion Price (ICP) = External Congestion Component + Net Interchange Scheduling Limit (NISL) Congestion Component.

External Congestion Component is the cost of congestion across the intertie when intertie limits are binding.

[11] See the Introduction to Ontario’s Physical Markets workbook available on the Training web page for information on Locational Marginal Prices for Ontario

NISL Congestion Component is the cost of congestion across all the interties when NISL is binding.

6.1 Intertie Boarder Price (IBP)

The IBP is the LMP at the Ontario side of an intertie. As such, it includes the Ontario reference price plus the costs of congestion and losses between the reference bus and the intertie with the external jurisdiction.

6.2 Intertie Congestion Price (ICP)

The ICP includes:

- the external congestion, as determined in the last pre-dispatch before the start of the dispatch hour, as well as.
- the congestion cost associated with the Net Intertie Scheduling Limit (NISL).

External Congestion Component

Let's look at a simplified example to illustrate the potential pricing impact of external intertie congestion.

Assume

An intertie can flow 200 MW of exports.

Four exports are bid:

- MP A bids for 60MW at a price of $15
- MP B bids for 50MW at a price of $20
- MP C bids for 50MW at a price of $25
- MP D bids for 50MW at a price of $30

Intertie Border Price (IBP) is $9

With this border price, all four transactions would be scheduled to 50 MW each for a total intertie schedule of 200 MW because they were all willing to pay more than the IBP is lower than their bid prices. This includes MP A who bid for 60 MW since they bid the lowest and since the total capacity of the intertie does not accommodate all 210 MW bid economically. Since this is the case, there is external congestion.

To determine the external congestion cost, the 200MW limit is relaxed by an incremental amount (easiest to think of as 1 MW) and the resulting change in costs determined. If the intertie could accommodate 201 MW, that would allow 1 additional MW of MP A's $15 bid to flow. The difference between the IBP of $9 and MP A's bid of $15 is $6. This becomes the external congestion cost.

Net Interchange Schedule Limit (NISL) Component

NISL is included in the DAM and pre-dispatch calculation engines to limit the net allowable change in intertie schedules across the top of an hour. As mentioned, intertie schedules are for one-hour blocks. Changes in schedules from one hour to the next are achieved by dispatching facilities within Ontario either up (to achieve net exports) or down (to accommodate net imports) to account for the total intertie schedule change across all interties. This ramping takes ten minutes, starting five minutes before the hour and ending five minutes after the start of the hour. NISL is respected to ensure Ontario resources can satisfy hour-to-hour ramping needs without adversely impacting reliability. NISL is set to plus or minus 700 MW, unless changed by the IESO to support reliability.

To respect NISL the day-ahead Market (DAM) and pre-dispatch (PD) calculation engines may reduce or increase imports and exports that would have otherwise been economically scheduled. When doing so, they take the impact on cost into consideration.

As an example, assume an Hour 1 net import schedule of 500 MW. For Hour 2, assume the pre-dispatch intertie price is $38 and that the following are the available import offers and export bids:

Transaction	Hour 2 Offers and Bids
Import A	1,300 MW@ $30
Import B	300 MW @ $35
Export C	100 MW @ $50
Export D	300 MW @ $34

With an intertie price of $38, Imports A and B and Export C would be economic. Export D would be uneconomic. If the three economic transactions were all scheduled in full, the resulting net schedule would be imports of 1,500 MW (1,300 MW plus 300 MW, less 100 MW). However, because Hour 1'snet schedule was 500 MW of imports, the net import schedule for Hour 2 must be limited to 500 MW plus the 700 MW NISL, or 1200 MW.

To produce a net import schedule of 1200 MW in hour 2, the DACP and pre-dispatch would evaluate the following options to determine what the impact on cost would be:

- The algorithm could choose not to schedule Import B. With an offer price of $35 and an intertie price of $38, it had been scheduled to 300 MW. Not scheduling this transaction would represent a cost of $38 less $35, or $3/MWh, or $900 in total. This is the amount that the import stood to benefit by if it had flowed. Not receiving it would, therefore, be a cost to be considered.

- Alternatively, the algorithm could schedule Export D. With a bid price of $34 and a price of $38, it had not been previously scheduled to flow. If Export D was now scheduled, it would be required to pay a price higher than it's bid. The difference between its bid and what it would be required to pay given the intertie price is $4/MWh. This represents a total cost of $1200.

Option	Economic Schedule	Schedule to Respect NISL	Offer/Bid Price	Cost [(Intertie Price – Offer/Bid Price) x Schedule Change to Respect NISL
Do not schedule Import B	300 MW	0 MW	$35	($38 - $35) x 300 MWh = $900
Schedule Export D	0 MW	300 MW	$34	($38 - $34) x 300 MWh = $1200

Therefore, the calculation engines will choose not to schedule Import B (and to leave Export D unscheduled) as this is the least cost solution to respect NISL.

The cost of NISL will be incorporated into the intertie price. To calculate the NISL congestion component for the intertie price, the DAM and pre-dispatch calculation engines will determine the savings resulting from expanding the NISL constraint by 1 MW. To determine this, the calculation engines will look at all possible solutions, including whether Import A and Export D could help. Import A cannot as it is already fully scheduled. Export D cannot because it is uneconomic and is not required to be scheduled to respect NISL. This makes Export D unavailable.

Transaction	Offers/Bids	Schedule to Satisfy 700 MW NISL	Eligible to satisfy next MW (i.e., 701 MW NISL)?	Savings (Difference Between IBP and Eligible Offer/Bid)
Import A	1,300 MW@ $30	1,300 MW	No	N/A
Import B	300 MW @ $35	0 MW	Yes	$38 - $35 = $3
Export C	100 MW @ $50	100 MW	Yes	$38 - $50 = -$12
Export D	300 MW @ $34	0 MW	No	N/A

Import B could flow 1 MW if the NISL constraint were relaxed by a megawatt. The savings associated with this would be the $3 difference between its offer price and the Intertie Border Price.

Because Export C bid at $50, it was fully scheduled while respecting the 700 MW NISL limit. If Export C was reduced by 1 MW to allow for additional import flow, there would be a cost of $12 since Export C was willing to pay up to $50 to export.

Therefore, the NISL price is set at Import B's $3 savings since it is the most economic outcome. The intertie price, then, would be the Intertie Border Price of $38 plus an ICP of -$3 (assuming no congestion due to the intertie limit) which equals $35. The NISL congestion price is negative because it is binding in the import direction.

That the price in this example dropped due to NISL congestion makes sense in terms of market dynamics – reducing the intertie price by $3 makes transacting imports less attractive and makes it more attractive to export. This is what one would want to have happen to resolve an import-congested intertie.

6.3 Real-Time Price Setting

Real-time will have dynamic intertie settlement pricing. The exact approach will depend on the whether the intertie was congested or not in the final pre-dispatch run:

- If there was no congestion (external congestion of a binding NISL) in pre-dispatch, the price will be the real-time intertie border price.
- If there was export congestion, the price will be the sum of the five-minute real-time intertie border prices and the pre-dispatch intertie congestion price.
- If there was import congestion, the price will be the lesser of the pre-dispatch intertie locational marginal price (that is, the pre-dispatch intertie border price, plus the cost of external congestion plus the cost of NISL), or the five-minute real-time intertie border prices,

7. The Intertie Offer Guarantee

Import transactions are locked in for the hour based on pre-dispatch prices. However, these transactions are settled using real-time prices. As a result, those conducting imports face a settlement price risk due to the scheduling process. Intertie offer guarantee (IOG) payments reduce this price risk for importers. IOG payments are intended to encourage imports, helping to ensure adequate supply in Ontario.

The RT_IOG will be offset where no net power is provided. The RT_IOG Offset will be applied to implied linked wheels, and real-time imports when the MP has DAM imports that were not scheduled in real-time for the hour. Please see Market Manual 5.5, Appendix D for an example of the IOG offset process.

Imports scheduled in the day-ahead market and real-time for the same MWs in the same hour and linked wheels are not eligible for a real-time intertie offer guarantee.

Real-time intertie offer guarantees are discussed in market manual 5.5: IESO-Administered Markets Settlement Amounts, section 2.18 and Appendix D where an example is presented.

Objectives

After completing this section users will be able to:

- Explain the purpose of the intertie offer guarantee
- Calculate an intertie offer guarantee payment
- Discuss the impact of implied wheel-throughs on the intertie offer guarantee

7.1 Calculation of the Real-Time Intertie Offer Guarantee (RT_IOG)

The RT_IOG ensures that, over the course of an hour, an importer will receive revenue at least equal to their schedule times their average offer price. By doing this, the RT_IOG ensures that an importer does not suffer a negative operating profit over the course of an hour. In other words, they are assured that they will receive at least a $0 operating profit. The IOG is calculated as follows:

IOG = Potential IOG – Offset MWs x IOG rate

To calculate the RT_IOG four (4) steps are performed:

1. Calculate the potential guarantee amount for each import based on MW scheduled:

$$\text{Potential IOG} = -1 \times \text{Min}[0, \sum OP(\text{RT_LMP}, \text{SQEI}, \text{BE}) - \sum OP(\text{RT_LMP}, \text{Min}[\text{SQEI}, \text{DAM_QSI}], \text{BE})]/12$$

2. Determine the $/MW rate for the resource:

$$\text{IOG Rate} = \text{Potential IOG} / \text{MW scheduled}$$

Determine the offset MWs by removing import MWs that are deemed as scheduled in DAM and by removing import MWs that are deemed to be part of an implied linked wheel. The offset will be done 3 times: on the intertie, neighbouring electricity system and Ontario level.

$$\text{Offset MW} = \sum\text{DAM Import MWs} + \sum\text{Implied Linked Wheel MWs}$$

3. Recalculate the IOG amount: IOG = Potential IOG – Offset MW x IOG rate

8. Compliance with IESO Interchange Schedules

If an interchange transaction fails to flow for a reason that was within the participant's control, that participant is subject to a settlement charge. In some cases, there may also be compliance actions, including penalties.

Objectives

After completing this section users will be able to:

- Explain the impact of interchange failures on IESO-controlled grid operations and IESO-administered markets
- Calculate both an import and an export failure settlement charge

8.1 Interchange Failures

Interchange transactions fail to flow for a variety of reasons. Some of these reasons are beyond a participant's control, such as being cut by a system operator. However, MP's can avoid others, including:

- Not entering a valid NERC tag
- Not successfully scheduling the transaction in the neighbouring jurisdiction

Interchange failures can have a significant impact on IESO-controlled grid operations and on IESO-administered markets:

- The IESO may have to replace a failed import by taking actions that increase market costs, either through increased uplift or higher prices
- For failed exports, the IESO may have to constrain off generation, which may lower the real-time price. Failed exports can also have operational impacts during low demand periods.

Because of these negative effects of failed interchange transactions, an automatic settlement charge is applied to a participant who fails to flow an interchange transaction if the reason for failure was within their control.

8.2 The Intertie Failure Charge (IFC)

The intertie failure charge is applicable to import or export transactions which fail in real-time.

8.2.1 DAM Intertie Failure Charge

An intertie failure charge will apply to day-ahead scheduled transactions which fail to flow in real-time for a reason within the MPs control. DAM failed MWs will be any MWs scheduled in the DAM and also scheduled by the last pre-dispatch before the start of the hour, but which do not flow in real-time. These MWs will be charged the real-time external congestion and real-time NISL costs.

8.3 DAM Import Failure Charge (DAM_IMFC)

The first step in calculating the DAM intertie failure charge is to calculate the total of DAM MWs failed. Once this is done, the total DAM_IMFC can be calculated.

8.3.1 Total of DAM MW's Failed (DAM_IMFC)

The total DAM MWs failed will be calculated as the greater of zero or the lesser of the DAM quantity scheduled for injection and the pre-dispatch quantity scheduled for injection less the real-time scheduled quantity of energy injected:

$$MAX\ (0,\ MIN\ (DAM_{QSI}\ ,\ PD_{QSI}) - RT_{SQEI})$$

Where:

- DAM_{QSI} – The quantity scheduled for injection day-ahead (i.e., the day-ahead import quantity)
- PD_{QSI} – The quantity scheduled for injection in the last pre-dispatch before the start of the dispatch hour (i.e., the pre-dispatch scheduled import quantity)
- RT_{SQEI} – The real-time scheduled quantity of energy injected (i.e., the actual import quantity which flowed in real-time)

Example

	DAM_{QSI}	PD_{QSI}	RT_{SQEI}	Failed DAM Quantity
Schedule 1	100	100	70	30
Schedule 2	100	120	70	30
Schedule 3	100	70	70	0

Schedule 1 had a DAM_{QSI} and PD_{QSI} of 100 MWs, but a RT_{SQEI} of 70 MWs. Therefore, 30 MWs failed.

Schedule 2 had a DAM_{QSI} of 100 MWs and a PD_{QSI} of 120 MWs, but a RT_{SQEI} of 70 MWs. Therefore, it also had a 30 MW failure because the lower of the DAM_{QSI} and PD_{QSI} is considered.

Using this same principle, schedule 3 had a DAM_{QSI} of 100 MWs but a PD_{QSI} and RT_{SQEI} of 70 MWs. As such, it did not have any failed MWs.

8.3.2 DAM_IMFC

The DAM Import Failure charge for each interval in an hour will be calculated as the sum of the lesser of zero or the real-time price of external congestion plus the real-time net interchange scheduling limit cost all times the DAM quantity of failed imports divided by twelve.

$$Sum\ of\ (MIN\ (0,(RT_{PEC}\ +\ RT_{NISL})\ X\ DAM_{Q\ IMPORT\ FAILED}\ /\ 12)$$

Where:

- RT_{PEC} – The real-time price of external congestion

- RT_{NISL} – The real-time net interchange scheduling limit cost

Example:

As an example, assume:

- The real-time price of external congestion is negative $3 because the intertie was export congested.
- The real-time net interchange scheduling limit cost is $2
- and the DAM quantity of failed imports is 30 MWs.

$$(MIN (0,(-\$3 + \$2) \times 30 / 12) = -2.50$$

This results in a failure charge of $2.50 for this interval.

Note that if the real-time price of external congestion had been positive $3, reflecting import congestion, the failure charge would have been zero, because the calculation would have used the lesser of 0 or $12.50.

The same calculation would be done for each five-minute interval in the hour

8.4 DAM Export Failure Change (DAM_EXFC)

Similar to imports, the first step in calculating the EXFC is to calculate the total DAM MWs failed. Once this is done, the total DAM_EXFC can be calculated.

8.4.1 Total of DAM MW's Failed (DAM_EXFC)

The total DAM export MWs failed will be calculated as the greater of zero or the lesser of the DAM quantity scheduled for withdrawal and the pre-dispatch quantity scheduled for withdrawal less the real-time scheduled quantity of energy withdrawn.

$$MAX (0, MIN (DAM_{QSW} , PD_{QSW}) – RT_{SQEW})$$

Where:

DAM_{QSW} – The quantity scheduled for withdrawal day-ahead (i.e., the day-ahead export quantity)

PD_{QSW} – The quantity scheduled for withdrawal in the last pre-dispatch before the start of the dispatch hour (i.e., the pre-dispatch scheduled export quantity)

RT_{SQEW} – The real-time scheduled quantity of energy withdrawn (i.e., the actual export quantity which flowed in real-time)

8.4.2 DAM_EXFC

The DAM Export Failure charge for each interval during an hour will be calculated as the sum of negative one (-1) times the greater of zero or the real-time price of external congestion plus the real-time net interchange scheduling limit cost all times the DAM quantity of failed exports divided by twelve

$$\text{Sum of } (-1) \times MAX (0, (RT_{PEC} + RT_{NISL}) \times DAM_{Q\ EXPORT\ FAILED} / 12)$$

Example:

As an example, assume:

- The real-time price of external congestion is $3 because the intertie is export congested.
- The real-time net interchange scheduling limit cost is $2.
- The DAM quantity of failed exports is 30 MWs.

$$(-1) \times MAX\ (0, (3 + 2) \times 30 / 12) = -12.50$$

This results in a failure charge of $12.50 for this interval.

The same calculation would be done for each five-minute interval in the hour.

8.4.3 Real-Time Intertie Failure Charges

A Real-Time Intertie Failure Charge will apply to import and export transactions scheduled in the last pre-dispatch before the start of the dispatch hour which are incremental to any scheduled day-ahead and which fail to be scheduled in real-time due to a reason within the participant's control. Please see Section 4.1.1.1 in Market Manual 4.3: Operation of the Real-Time Market for information on intertie coding and intertie failure charge application.

The failure charge will be applied to the portion of the pre-dispatch schedule that is greater than the DAM schedule. This means the charge covers both transactions wholly scheduled after the completion of the DAM and those where the quantity of a day-ahead scheduled transaction was subsequently increased.

In the calculations, real-time prices will be adjusted by a Price Bias Adjustment Factor. This adjusts the real-time price for the effect of systemic differences between pre-dispatch and real-time price calculations.

Similar to the day-ahead failure charges, the formula for the real-time failure charges will include the costs of intertie congestion and NISL.

8.5 RT Import Failure Charge (RT_IMFC)

The first step in calculating the RT_IMFC is to calculate the total DAM MWs failed. Once this is done, the total RT_IMFC can be calculated.

8.5.1 The Total Real-Time Import MWs Failed (RT_IMFC)

The total real-time import quantity failed will be calculated as the greater of zero or the pre-dispatch quantity scheduled for injection from the last pre-dispatch before the start of the dispatch hour less the greater of the DAM quantity scheduled for injection or the real-time scheduled quantity of energy injected.

$$MAX\ (0, PD_{QSI} - MAX\ (DAM_{QSI}\ , RT_{SQEI}))$$

Example:

	PD_{QSI}	DAM_{QSI}	RT_{SQEI}	Failed RT Quantity
Schedule 1	100	100	80	0
Schedule 2	130	100	70	30
Schedule 3	100	70	70	30

For Schedule 1 in the example, the failed import MWs were zero because both the pre-dispatch quantity scheduled for injection and the DAM quantity scheduled for injection were 100 MWs. So, subtracting the DAM quantity from the pre-dispatch quantity results in zero.

For Schedule 2, 30 MWs failed because the greater of the real-time scheduled quantity of energy injected, or 70 MWs, and the DAM quantity scheduled for injection, or 100 MWs, is subtracted from the pre-dispatch quantity scheduled for injection of 130 MWs.

Lastly, Schedule 3 had 30 MWs of failed imports since both the DAM quantity scheduled for injection and the real-time scheduled quantity of energy injected were 70 MWs.

8.5.2 RT_IMFC

The Real-Time Import Failure charge is calculated as the sum of negative one times the lesser of the greater of zero or the real-time intertie border price plus the import price bias adjustment factor less the pre-dispatch intertie border price all times the real-time import quantity failed, or the greater of zero or the real-time intertie border price times the real-time import quantity failed, plus the lesser of zero or the real-time price of external congestion plus the real-time net intertie scheduling limit cost times the real-time import quantity failed all divided by twelve.

$$\Sigma\ [(-1)\ X\ MIN\ (MAX\ (0,(RT_{IBP} + PBAF_I - PD_{IBP})\ X\ RT_{Q\ IMPORT\ FAILED}),\ MAX\ (0,\ RT_{IBP}\ X\ RTQ\ IMPORT\ FAILED\ ))\ +\ MIN\ (0,\ (RT_{PEC} + RT_{NISL})\ x\ RT_{Q\ IMPORT\ FAILED})]\ /\ 12)$$

Where:

- PD_{IBP} – The pre-dispatch Intertie Border Price
- RT_{IBP} – The real-time Intertie Border Price
- RT_{PEC} – The real-time price of external congestion
- RT_{NISL} – The real-time net interchange scheduling limit cost

Example:

Assume that:

- The real-time intertie border price is $30, and the pre-dispatch intertie border is $25;
- The import price bias adjustment factor is $2.30;
- The real-time price of external congestion is $3;
- The real-time net intertie scheduling limit cost is $2; and
- Lastly, the real-time quantity of imports failed is 30 MWs

The RT Import Failure charge will be calculated as follows:

$$\Sigma [(-1) \times MIN (MAX (0,(30 + 2.30 – 25) X 30), MAX (0, 30 x 30)) + MIN(0,(3 + 2) x 30)] / 12)$$

$$= [(-1) X MIN (MAX (0, 7.30 X 30), MAX (0, 900)) + MIN(0, 5 x 30)] /12$$

$$= [(-1) X 219 + 0] / 12$$

$$= -\$18.25$$

Applying these numbers to the formula would result in a charge for this interval of $18.25.

As with the DAM import failure charge, the same calculation would be done for each five-minute interval in the hour.

8.6 RT Export Failure Charge (RT_EXFC)

The first set in calculating the real-time export failure charge is to calculate the total of DAM MW's failed. Once this is done, the total RT_EXFC can be calculated.

8.6.1 The Total Real-Time Export MWs Failed (RT_EXFC)

The total real-time export quantity failed will be calculated as the greater of zero or the pre-dispatch quantity scheduled for withdrawal from the last pre-dispatch before the start of the hour less the greater of the DAM quantity scheduled for withdrawal or the real-time scheduled quantity of energy withdrawn.

$$MAX (0, PD_{QSW} – MAX (DAM_{QSW} , RT_{SQEW}))$$

8.6.2 RT_EXFC

The real-time export failure charge for an interval during an hour will be calculated as the sum of negative one times the lesser of the greater of zero or the pre-dispatch intertie border price less the export price bias adjustment factor less the real-time intertie border price all times the real-time exports quantity failed or the greater of zero or the pre-dispatch intertie border price times the real-time export quantity failed less the greater of zero or the real-time price of external congestion plus the real-time net interchange scheduling limit cost times the real-time export MWs failed all divided by twelve.

$$\Sigma [(-1) \times MIN (MAX (0, (PD_{IBP} - PB_{AFE} - RT_{IBP}) \times RT_{Q\ EXPORT\ FAILED}), MAX (0, PD_{IBP} \times RT_{Q\ EXPORT\ FAILED})) - MAX (0,(RT_{PEC} + RT_{NISL}) \times RT_{Q\ EXPORT\ FAILED})] / 12)$$

Example:

Assume that:

- The real-time intertie border price is $25, and the pre-dispatch intertie border price is $30;
- The export price bias adjustment factor is $3.01;
- The real-time price of external congestion is $3;
- The real-time net intertie scheduling limit cost is $2; and
- Lastly, the real-time quantity of exports failed is 30 MWs

The real-time Export Failure charge will be calculated as follows:

$$\Sigma [(-1) X MIN (MAX (0,(30 - 3.01 - 25) X 30), MAX (0, 30 x 30)) - MAX (0,(3 + 2) x 30)] / 12)$$

$$= [(-1) X MIN (MAX (0, 1.99 X 30), MAX (0, 900)) - MAX (0, 150)] / 12$$

$$= [(-1) X 59.7 - 150] / 12$$

$$= (-59.7 - 150) /12$$

$$= -\$209.70$$

Applying these numbers to the formula would result in a charge for this interval of $209.70.

The same calculation would be done for each five-minute interval in the hour.

8.7 Price Bias Adjustment Factor

Prices will be adjusted in real-time failure charge calculations by a 'Price Bias Adjustment Factor'. This factor compensates for systematic differences between how prices are calculated in pre-dispatch and how they are calculated in real-time. For example, pre-dispatch is an hourly calculation that projects future prices using expected demand for the hour whereas in real-time, prices are set every five minutes using updated demand forecasting.

The Price Bias Adjustment Factor page of the IESO website lists the factors. The variables used in settlements for the Price Bias Adjustment Factor are:

- PBAFI – The Price Bias Adjustment Factor for Imports
- PBAFE – The Price Bias Adjustment Factor for Exports

9. Make Whole Payments (MWP)

There can be situations where an intertie transaction may be scheduled in such a way that it deviates from its energy or operating reserve economic operating point causing an implied lost cost or an implied lost opportunity. This can result from a manual control action or as a result of differences between pre-dispatch scheduling and the real-time pricing pass. If this happens, a make-whole payment (MWP) will compensate for any loss. MWP's help maintain reliability, as they incentivize market participants to follow their schedules.

Objectives

After completing this section users will be able to:

- Explain the role and impact of the make-whole payment.
- Calculate both the day-ahead and real-time make-whole payment.

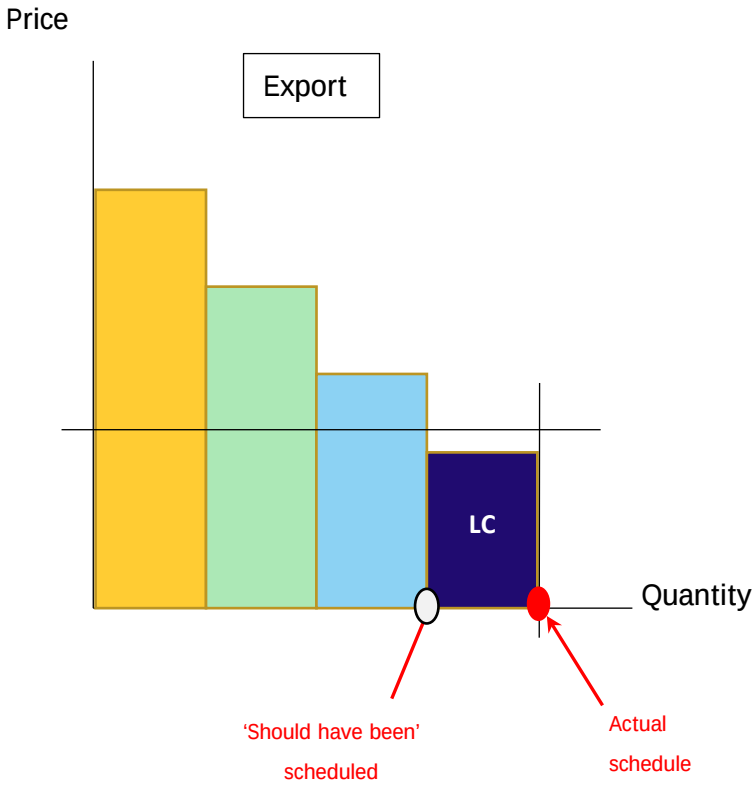
MWP's are designed to pay for the financial difference between where a resource was actually dispatched to, and where it otherwise would have been based on the LMP and its offer or bid curve but-for a binding constraint.

In order to calculate an MWP, one needs dispatch schedules, offer/bid curves, LMPs, and a determination of the 'ideal dispatch' schedule. The resource's economic operating point (EOP) is its ideal dispatch schedule.

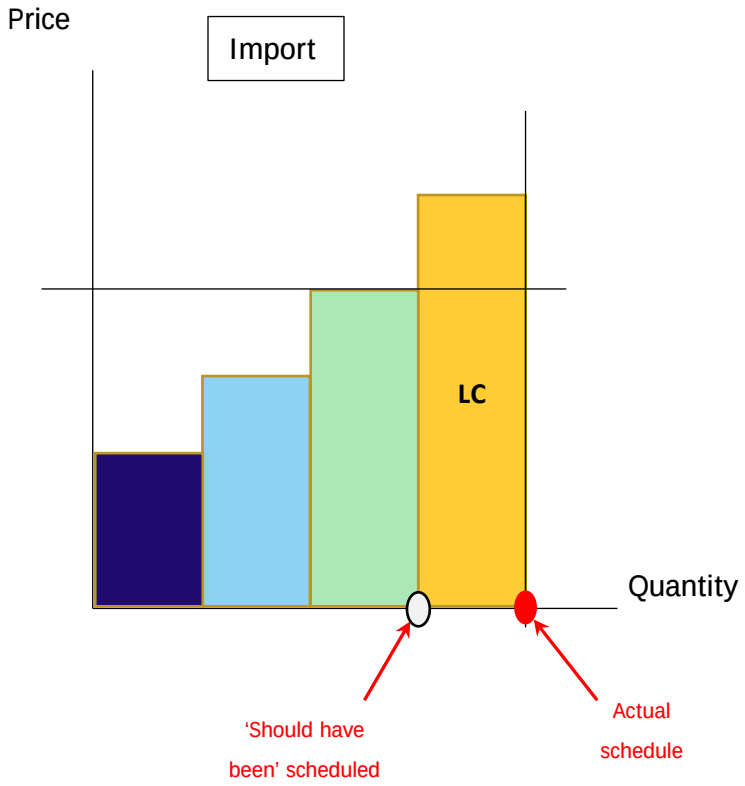
9.1 Lost Cost

Lost cost scenarios occur when the LMP implies the resource should have been scheduled lower:

- For an export, lost cost would occur when it is scheduled above its EOP so the energy or operating reserve real-time price is higher than its bid price.



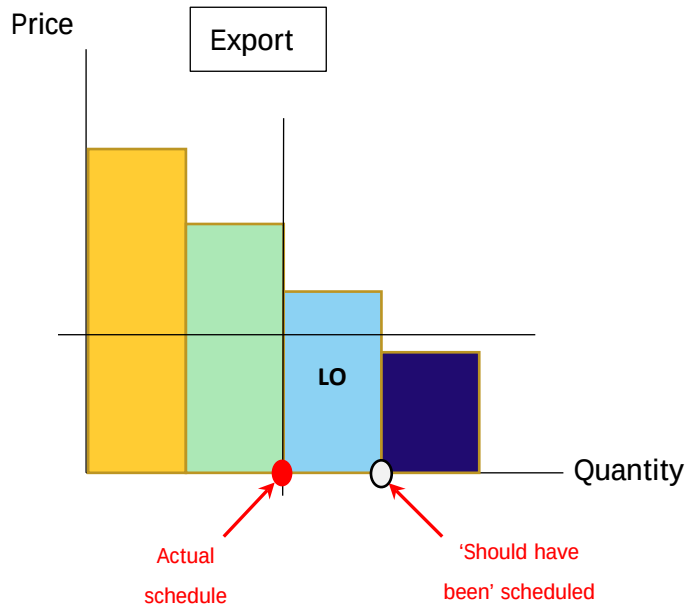
- For an import transaction, this occurs when it is scheduled above its economic operating point (or EOP) so its energy or operating reserve cost is greater than the real-time price.



9.2 Lost Opportunity

Lost opportunity scenarios occur when the LMP implies the resource should have been scheduled higher:

- For exports, this occurs when it is scheduled below its EOP – in this case so it is unable to realize its full potential economic benefit of exporting.



- For an import transaction a lost opportunity cost occurs when it is scheduled below its economic operating point so it is unable to earn additional market revenue above its market cost.



9.3 The Types of MWPs and EOPs

The renewed market includes three types of MWP's:

1. Lost Cost MWP for the Day-Ahead Market (DAM).
2. Lost Cost MWP for the Real-Time Market (RTM) incremental to the DAM Lost Cost MWP.
3. Lost Opportunity MWP for the RTM.

Lost opportunity MWPs are not required in DAM since opportunity costs are not fully realized until real-time.

9.3.1 DAM Lost Cost Make-Whole Payment

Intertie transactions are eligible for the day-ahead make-whole payment (DAM_MWP). The DAM_MWP provides a settlement amount for resources that are scheduled in the day-ahead market when the market participant would incur an implied loss. An implied loss is incurred when the energy and operating reserve revenue earned is insufficient to cover the offer costs or bid benefits of the MP.

The calculation engines will maximize the gains from trade over their entire look-ahead periods given market participant offers and bids, resource constraints and the reliability needs of the system. At times, however, the most efficient and reliable schedule for the system as a whole can result in some transactions being scheduled at an implied loss.

At a high level, the formula for calculating a DAM make-whole payment is:

$$DAM_MWP = DAM_COMP1 + DAM_COMP2$$

Where:

- DAM Component 1 is the make-whole payment for energy. This is equal to negative one times the operating profit based on the day-ahead market quantity scheduled for injection less the operating profit based on the day-ahead market economic operating point.

$$= -1 \times [OP(DAM_QSI) - OP(DAM_EOP)]$$

- DAM Component 2 is the make-whole payment for operating reserve. This is equal to negative one times the operating profit based on the day-ahead market quantity of operating reserve scheduled for injection less the operating profit based on the day-ahead market operating reserve economic operating point.

$$= -1 \times [OP(DAM_QSOR) - OP(DAM_OR_EOP)]$$

Example:

Assume an import is scheduled uneconomically above its economic operating point (EOP) for energy in DAM in HE3. It offered to import up to 100 MW if the price was $10 or greater, up to 200 MW if the price was $20 or greater, up to 300 MW if the price was $30 or greater, and up to 400 MW if the price was $40 or more. In the DAM, the intertie price was $20.

Based on this price, its economic operating point would be 200 MW since it offered to supply that if the price was at least $20. The DAM, however, scheduled it for 250 MW – which is 50 MW above its EOP.

PQ #	Price ($/MWh)	Quantity (MW)
1	10	0
2	10	100
3	20	200
4	30	300
5	40	400

DAM Price	$
DAM_LMP	$20

DAM Schedule and EOP	Quantity (MW)
DAM_QSI	250
DAM_EOP	200

Applying this information to the DAM Component 1 formula.

DAM_COMP1 = -1 x [OP(DAM_QSI) – OP(DAM_EOP)]		
	OP (DAM_QSI)	OP (DAM_EOP)
Revenue	250MW x $20 = $5,000	200MW x $20 = $4,000
Costs	(100MW x $10) + (100MW x $20) + (50MW x $30) = $4,500	(100MW X $10) + (100MW x $20) = $3,000
Net	$5,000 - $4,500 = $500	$4,000 - $3,000 = $1,000
DAM COMP1	-1 x ($500 - $1000) = $500	

The operating profit based on the DAM quantity scheduled for injection is revenue less costs. Revenue would be the 250 MW quantity scheduled for injection times the DAM intertie price of $20 for a total of $5,000.

Costs to deliver 250 MW would be $4,500. This is found by looking at the import offer laminations. As discussed, this import was offered as $10 for the first 100 MW and $20 for the next 100 MW. The final 50 MW of the 250 MW quantity scheduled for injection would come from the next offer lamination at $30.

Therefore, the net operating profit based on the DAM quantity scheduled for injection is $500.

9.3.2 Real-Time Market Make-Whole Payment

A real-time MWP may be payable for transaction quantities over and above that which were scheduled day-ahead – this includes transactions wholly scheduled after close of the DAM, or additional quantities scheduled in pre-dispatch above that which was scheduled for a transaction in the DAM.

The formula for the real-time make-whole payment will be the greater of zero or the energy lost cost plus the operating reserve lost cost plus the greater of zero or the energy load opportunity cost plus the operating reserve lost opportunity cost.

$$RT_MWP = Max\ (0,\ Energy\ Lost\ Cost + OR\ Lost\ Cost) + Max(0,\ Energy\ Lost\ Opportunity\ Cost + OR\ Lost\ Opportunity\ Cost\ )$$

Example:

In this example, an export was scheduled uneconomically. Based on its bid, and the pre-dispatch price of $25, its economic operating point was 200 MW. However, it was scheduled to 300 MW in pre-dispatch. In real-time, the LMP was $30. It was scheduled to 300 MW for real-time as well although its economic operating point was only 200 MW.

Energy Bids – Dispatch Data		
PQ #	Price ($/MWh)	Quantity (MW)
1	40	0
2	40	100
3	30	200
4	20	300
5	10	400

The price in both the last pre-dispatch before the start of the hour and real-time exceeded the export bid cost. Therefore, the export will be compensated for lost cost based on the lesser of the pre-dispatch or real-time LMP.

RT Energy Lost Cost Calculation		
	OP (Max (SQEW, DAM_QSW))	OP (Max (RT_LC_EOP, DAM_QSW))
Revenue	300MW x $25 = $7,500	200MW x $25 = $5,000
Costs	100MW x $40 + 100MW x $30 + 100MW x $20 = $9,000	100MW X $40 + 100MW x $30 = $7,000
Net	$7,500 - $9,000 = -$1,500	$5,000 - $7,000 = -$2,000
RT_ELC	Max (0, -$1,500 - -$2,000) = $500	

In this example, the export's real-time make-whole payment would be $500.

10. Energy Settlements

The physical market has a two-settlement system; day-ahead scheduled transactions will be settled using day-ahead LMPs, while deviations from day-ahead schedules in real-time (including those which were scheduled only in pre-dispatch) are settled using real-time LMPs.

Objectives

After completing this section users will be able to:

- Explain the two-settlement system used for intertie transactions
- Utilize the provided formula to calculate the overall intertie energy settlement amount, considering both day-ahead and real-time components
- Explain the purpose of various settlement amounts including: DAM BC, DAM MWP, RT MWP, Hourly Uplifts, Non-Hourly Uplifts, and External Congestion and NISL Residuals

The IESO uses a two-settlement system through which the DAM and RTM are each settled separately. For example, day-ahead scheduled export transactions will appear under CT 1112 while real-time export transactions will appear under CT 1113..

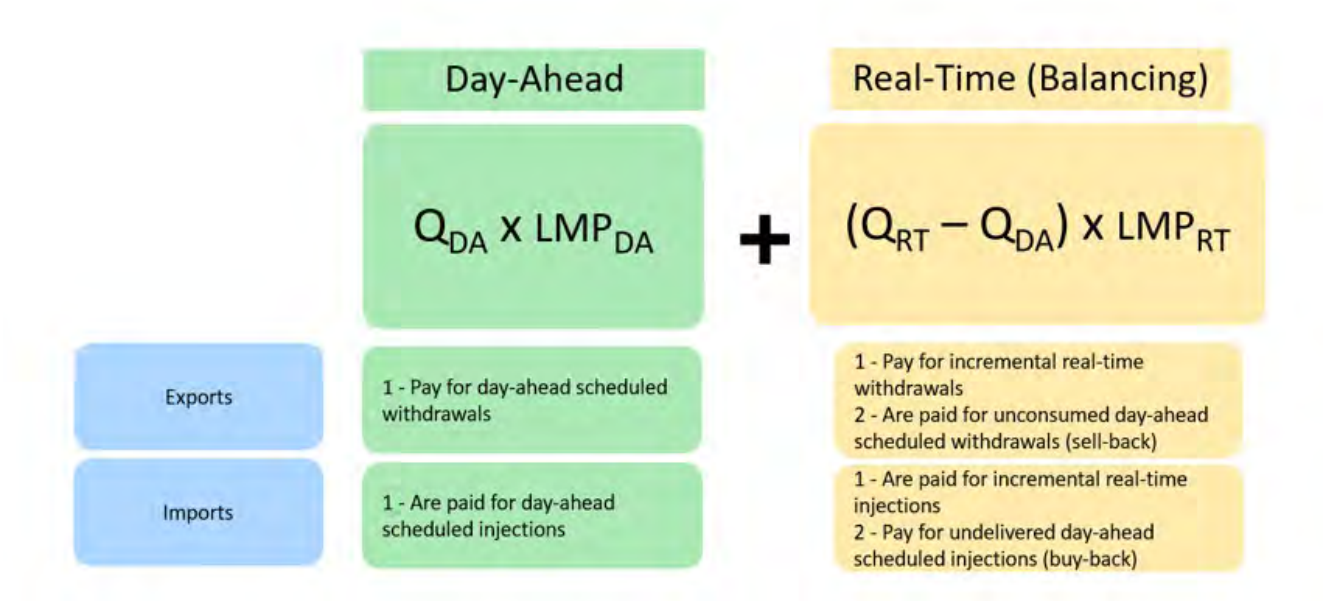
The DAM is settled on an hourly basis, so schedules and prices are for an entire hour. The general formula for DAM energy settlement is the day-ahead quantity times the day-ahead locational marginal price:

DAM Quantity Scheduled X DAM LMP

The RTM operates on a five-minute basis, so it's prices and schedules are determined for each of the 12 five-minute periods in an hour. Intertie transaction schedules are the same for each interval, unless curtailed during the hour for reliability. The general formula for RTM energy settlement is the difference between the quantity injected/withdrawn in real-time less the quantity scheduled in day-ahead times the five-minute real-time locational marginal price:

(RTM Quantity Actually Injected/Withdrawn – DAM Quantity Scheduled) X RTM LMP

The combination of the two above formulas represents the overall effect of the two-settlement system. A simplified formula for overall intertie energy settlement (i.e., total of day-ahead and real-time) is:



10.1 Hourly Uplifts and Non-Hourly Uplifts

Similar to the current market, hourly uplifts[14] are collected or disbursed on a pro-rata basis to loads and exports that consume in real-time. Refer to Market Rules Chapter 9, section 3.9 for more information uplifts. Non-hourly uplifts are collected or disbursed on a pro-rata basis to loads and exports that consume in real-time.

[14] Refer to Market Rules Chapter 9, section 4 for more information

11. Day-Ahead Balancing Credit

The day-ahead balancing credit (DAM_BC) provides compensation to offset a negative buy-back incurred when the IESO curtails day-ahead scheduled imports or exports in real-time due to a reliability need.

Objectives

After completing this section users will be able to:

- Explain the role of the DAM Balancing Credit.
- Utilize the provided formula to calculate the overall intertie energy settlement amount, considering both day-ahead and real-time components.
- Explain the purpose of various settlement amounts including DAM_BC, DAM_MWP, RT_MWP, Hourly Uplifts, Non-Hourly Uplifts, and External Congestion and NISL Residuals.

An intertie trader may be eligible for compensation through a DAM_BC if:

- Their day-ahead scheduled transaction is reduced or cut by the IESO in order to maintain reliability, or
- Their transaction was activated for operating reserve.

The DAM_BC will not apply, however, if:

- The transaction was part of a linked wheel
- The transaction is an energy import, and
- The DAM LMP is equal to or higher than the real-time LMP; or
- The lesser of the real-time economic operating point or the DAM quantity scheduled for injection is less than the real-time scheduled quantity of energy injected
- The transaction is an energy export, and:
- The DAM LMP is equal to or less than the real-time LMP; or
- The lesser of the real-time economic operating point or the DAM quantity scheduled for injection is less than the real-time scheduled quantity of energy withdrawn
- It is an operating reserve transaction, and:
- The DAM OR price is equal to or greater than the real-time OR price; or
- The lesser of the real-time economic operating point or the DAM OR quantity scheduled is less than the real-time OR scheduled quantity

11.1 DAM Energy Balancing Credit Formulas

The DAM energy balancing credit for imports is calculated as the operating profit given the real-time LMP and the lesser of the DAM quantity scheduled for injection or the real-time lost opportunity cost economic operating point less the operating profit at the real-time scheduled quantity of energy for injection given the real-time LMP.

$$= MAX\ (0,\ OP\ (RT__{LMP},\ MIN(DAM__{QSI},\ RT_LOC_EOP),\ BE) - OP\ (RT__{LMP},\ SQEI,\ BE)$$

The DAM energy balancing credit for exports is calculated as negative one times the lesser of zero or the operating profit given the real-time LMP or the lesser of the DAM schedule or the real-time lost opportunity cost economic operating point or the energy bid less the operating profit at the real-time scheduled quantity of energy for withdrawal given the real-time LMP or the energy bid.

$$= (-1)\ x\ MIN(0,\ OP\ (RT__{LMP},\ MIN(DAM__{QSW},\ RT_LOC_EOP),\ BL) - OP\ (RT__{LMP},\ SQEW,\ BE))$$

Example One – Import constrained down in real-time

Let's go through an example of an import that has been constrained down. Assume an import was offered as follows:

- Up to 50 MWs if the price is $25 or greater,
- Up to 70 MWs if the price is $30 or greater, and
- Up to 100 MWs if the price is $50 or greater.

Further, assume there is a real-time LMP of $50 and a DAM LMP of $20. The DAM quantity scheduled for injection was 100 MWs but in real-time, only 30 MWs was scheduled.

Schedules, LMP, EOP		
Type	Quantity	Units
RT LMP	50	$
DAM LMP	20	$
DAM QSI	100	MW
SQEI	30	MW
RT LOC EOP	70	MW

The real-time lost opportunity cost economic operating point is 70 MW since the real-time price was $50 which would normally mean that this transaction would be scheduled to 70 MW.

This import is eligible for the DAM Balancing Credit because:

- The real-time LMP is higher than the DAM LMP, and
- The DAM quantity scheduled for injection is higher than the real-time scheduled quantity of energy injected

In this example, the day-ahead schedule was 100 MW, and the lost opportunity cost economic operating point was 70 MW. So, the revenue portion of the operating profit calculation in the first part of the equation would be equal to 70 MW times $50 or $3,500.

If 70 MWs had been scheduled, the cost given the offer laminations would be equal to $25 for the first 50 MWs plus $30 for the next 20 MW for a total of $1,850.

This would make the net operating profit for the first part of the equation (i.e., MAX (0, OP (RT_LMP, MIN(DAM_QSI, RT_LOC_EOP), BE)) equal to $3,500 minus $1,850 or $1,650.

The second part of the equation (i.e., – OP (RT_LMP, SQEI, BE)) is the operating profit given the real-time scheduled quantity for injection.

Given that 30 MWs flowed in real-time, revenue was 30 MWs times the real-time LMP of $50 which equals $1,500.

The cost for 30 MWs based on the submitted offer laminations is $25 per MW for a total of $750. Therefore, operating profit is $1,500 minus $750 or $750.

Therefore, the DAM Energy Balancing Credit in this example is $1,650 less $750 or $900. In this way, the market participant will receive in total the operating profit they should have based on the lesser of their day-ahead schedule or their real-time lost opportunity cost economic operating point.

Example Two - Export constrained down in real-time

For this next example, assume an export was bid as follows:

- Up to $10 to export 70 MWs,
- Up to $5 to export 100 MWs, and
- If the price is $2 or less, they are willing to export up to 120 MWs.

For our example, assume there is a real-time LMP of $6 and a DAM LMP of $15. The DAM quantity scheduled for withdrawal was 100 MWs but in real-time, only 30 MWs was scheduled.

The real-time lost opportunity cost economic operating point is 70 MWs since the real-time price was $6 which would normally mean that this transaction would be scheduled to 70 MWs.

Schedules, LMP, EOP		
Type	Quantity	Units
RT LMP	6	$
DAM LMP	15	$
DAM QSW	100	MW
SQEW	30	MW
RT LOC EOP	70	MW

This export is eligible for the DAM Balancing Credit because:

- The real-time LMP is lower than the DAM LMP, and
- The DAM quantity scheduled for withdrawal is higher than the real-time scheduled quantity of energy withdrawn.

As a reminder, the DAM energy balancing credit for exports is the operating profit given the real-time LMP and the lesser of the DAM schedule or the real-time lost opportunity cost economic operating point less the operating profit at the scheduled quantity of energy for withdrawal given the real-time LMP or the export bid.

OP (RT_LMP, MIN (DAM_QSW, RT_LOC_EOP), BL) – OP (RT_LMP, SQEW, BE)

The cost portion of the operating profit calculation in the first part of the equation (i.e., OP (RT_LMP, MIN (DAM_QSW, RT_LOC_EOP), BL)) would be 70 MWs times $6 which equals $420.

With 70 MWs scheduled, the cost given the bid laminations would be 70 MWs times $10 which equals $700.

As such, the net operating profit for the first part of the equation is $420 minus $700 which equals negative $380.

The second part of the equation (i.e., OP (RT_LMP, SQEW, BE)) is the operating profit given the 30 MW real-time scheduled quantity of energy withdrawn.

Given a $6 real-time LMP, the cost to export 30 MWs was $180.

The market participant bid $10 to export up to 30 MWs, so their bid cost was $300. This would make their resulting operating profit negative $120.

Therefore, the DAM Energy Balancing Credit for this export is equal to negative one times the lesser of zero or negative $380 less negative $120, or $260.

12. Market Power Mitigation

Intertie traders are subject to the IESO's Market Power Mitigation (MPM) framework as it relates to potential economic withholding on uncompetitive intertie zones. Uncompetitive intertie zones are determined by the IESO in accordance with Market Manual 14.1, section 3 and will be published on the IESO website.

Mitigation will be evaluated ex-post[20] for intertie transactions. This process uses conduct and impact tests to identify instances of economic withholding of energy and operating reserve on uncompetitive interties. The conduct test will determine if offers for energy bids for energy, or offers for operating reserve were submitted at prices significantly higher than intertie reference levels.

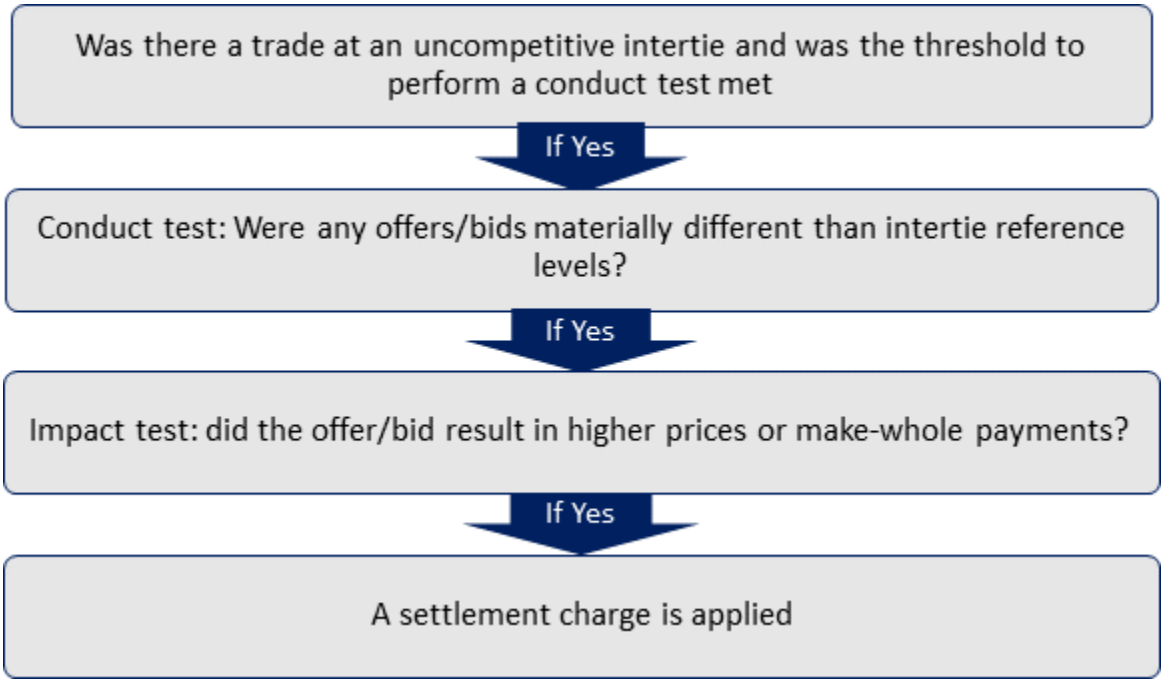
Export bids are not assessed for intertie economic withholding unless they meet the conditions related to market control entities found in Market Rules Chapter 7, section 22.17.11.1. Under this market rule, export bids are only assessed for intertie economic withholding if the relevant energy trader has disclosed a market control entity that has also been designated as a market control entity for physical withholding for a dispatchable resource that is authorized to supply energy or operating reserve in the Ontario physical market. The impact test will determine if prices or make-whole payments were greater by a specified threshold than those that would have occurred if the intertie reference levels were submitted. If both the conduct and impact tests are failed, it would result in a settlement charge to the market participant. An illustration of this process is provided below. The process for assessing uncompetitive intertie zones is conducted by the IESO in accordance with the process detailed in Market Manual 14.1, section 6 and Market Rules Chapter 7, section 22.17-22.19.

The IESO may assess intertie economic withholding by a boundary entity resource in either or both of the day-ahead market and the real-time market for a given dispatch day. If the IESO selects a single market, the IESO will deem the megawatt hours withheld in the other market to be zero for all relevant dispatch hours when calculating the intertie economic withholding settlement amount.

Participants whose transactions were mitigated will be confidentially notified and provided an opportunity to provide supplementary information prior to issuance of a settlement charge.

At a high level, the process for assessing economic withholding at an intertie involves asking a few questions. The answer must be yes to all of them for a settlement charge to be applied.

[20] For more information regarding how ex-post mitigation is applied for intertie traders, refer to Market Manual 14.1, section 6.



For intertie traders, intertie reference levels are established based on the previous 90 days of intertie trading activity. For detailed information regarding the IESO's process for determining intertie reference levels, refer to Market Rule Chapter 7, section 22.16.

If the IESO determines that an energy bid or offer or offer for operating reserve failed an impact test, the IESO will issue a first notice of economic withholding to the relevant market participant within 180 days of when the instance occurred.

Within 45 days after the date of the notice, the market participant can submit a request that the IESO determine an alternative intertie reference level value for the relevant boundary entity resource during the dispatch day in which the offer or bid was submitted. The request must include documentation to support any resource-specific considerations that were not accounted for when the intertie reference levels were determined which were used when the instance of intertie economic withholding was determined.

Within 90 days after the receipt of a reconsideration request or, if none is submitted, after the 45 days elapses, the IESO will complete its analysis and notify the registered market participant whether a settlement charge will be imposed. If this is the case, it will appear on the settlement statements for the next available month end.

13. Reports

The IESO produces a number of reports relevant to intertie traders. Several are described below.

13.1 Pre-DAM Reports

Report Name	Public or Private	Description
Adequacy Report	Public	Overall system conditions including any expected surplus/shortfalls, published at various times throughout the day-ahead and pre-dispatch timeframes including daily at 5:30 and 9:00 EPT
Day-Ahead Area Reserve Constraints Report (Pre-DAM)	Public	Hourly maximum and minimum constraints for the area operating reserve regions expected to be used by the DAM engine, published daily at approximately 9:00 EPT
Day-Ahead Intertie Scheduling Limits Report (Pre-DAM)	Public	Expected intertie scheduling limits to be used by the DAM engine, published daily at approximately 09:00 EPT

13.2 DAM Reports

Report Name	Public or Private	Description
Day-Ahead Area Reserve Constraints Report	Public	Hourly maximum and minimum constraints for the area operating reserve regions used by the DAM engine, published at approximately 13:30 EPT
Day-Ahead Intertie Scheduling Limits Report	Public	Actual intertie scheduling limits used by the DAM engine, published after DAM completion
Day-Ahead Hourly Intertie Energy Price Report	Public	Intertie LMPs for energy, including LMP components for all intertie locations, published after DAM completion
Day-Ahead Hourly Intertie Operating Reserve Price Report	Public	Intertie LMPs for operating reserve, including LMP components for all intertie locations, published after DAM completion

Day-Ahead Schedule Report	Private	Hourly DAM energy and operating reserve intertie schedules, issued after DAM completion
Dispatch Data Report for the Day-Ahead Scheduling Process	Private	Daily confirmation of an MP's daily and hourly dispatch data submitted into the DAM, issued after DAM completion

13.3 Pre-dispatch Reports

Report Name	New or Existing	Public or Private	Description
Pre-dispatch Intertie Scheduling Limits Report	Existing	Public	Actual intertie scheduling limits used by the PD engine, published after PD completion around 30 minutes past the hour
Pre-Dispatch Hourly Intertie Energy Price Report	New	Public	Intertie LMPs for energy for all hours of the PD look-ahead period, including LMP components for all intertie locations, published after PD completion around 30 minutes past the hour
Pre-Dispatch Hourly Intertie Operating Reserve Price Report	New	Public	Intertie LMPs for operating reserve for all hours of the PD look-ahead period, including LMP components for all intertie locations, published after PD completion around 30 minutes past the hour
Pre-Dispatch Schedules Report	Existing	Private	Hourly energy and operating reserve intertie schedules for all hours of the PD look-ahead period, issued after PD completion around 30 minutes past the hour
Pre-dispatch Intertie Transactions Report and GOG Eligible Extensions Reports	New	Private	For intertie traders, schedules for energy and operating reserve for the first two hours of the PD look-ahead period only, issued 15 minutes past the hour

13.4 Real-Time Reports

Report Name	New or Existing	Public or Private	Description
Real-Time Intertie Scheduling Limits Report	Existing	Public	Actual intertie scheduling limits for each five-minute interval used by the RTM engine, published after every interval

Intertie Schedule and Flow Report	Existing	Public	Total quantities of energy included in interchange schedules and quantities of energy that have been conveyed to and from each intertie zones for each five-minute interval using hourly averages, published every hour
Real-Time 5-Minute Intertie Energy Price Report	New	Public	Intertie LMPs for energy for each five-minute interval, including LMP components for all intertie locations, published after every interval
Real-Time 5-Minute Intertie Operating Reserve Price Report	New	Public	Intertie LMPs for operating reserve for each five-minute interval, including LMP components for all intertie locations, published after every interval

14. Skill Check Two

1. Intertie traders are subject to the IESO's Market Power Mitigation (MPM) framework as it relates to potential economic withholding on uncompetitive intertie zones. (Select True or False)
   a) True
   b) False

2. Which of the following tests are used by the IESO to identify instances of economic withholding of energy and operating reserve on uncompetitive interties? (Select the correct answer)
   a) Conduct test and impact test
   b) Efficiency test and reliability test
   c) Supply test and demand test
   d) Price test and quantity test

3. Which of the following statements about congestion rents is correct? (Select the correct answer)
   a) Congestion rents result from price differentials created by non-binding transmission constraints.
   b) Congestion rents occur when lower priced supply on one side of a constraint cannot fully serve demand on the other side, leading to higher priced supply serving the remaining demand.
   c) Congestion rents are unrelated to transmission constraints and are solely based on supply and demand.
   d) Congestion rents are collected only in the day-ahead market.

4. Imports are paid the price in the intertie zone while exports pay the price in the zone through which they are exporting. (Select True or False)
   a) True
   b) False

5. Which components make up the Intertie Locational Marginal Price (LMP)? (Select the correct answer)
   a) Reference Bus Component, Loss Component, and Internal Congestion Component
   b) Intertie Border Price (IBP) and Intertie Congestion Price (ICP)
   c) External Congestion Component and Net Interchange Scheduling Limit (NISL) Congestion Component
   d) All of the above

6. What is the Net Interchange Scheduling Limit (NISL) and why is it important? (Select the correct answer)
   a) NISL is the maximum allowable flow limit for intertie transactions; it ensures Ontario resources can satisfy hour-to-hour ramping needs without adversely impacting reliability.
   b) NISL is the price paid for intertie transactions; it determines the cost of imports and exports.
   c) NISL is the total amount of energy scheduled for import and export; it balances the supply and demand in the Ontario market.
   d) NISL is the limit on the number of transactions that can be scheduled; it prevents market congestion.

7. The DAM Energy Balancing Credit for exports is calculated based on the operating profit given the real-time LMP and the lesser of the DAM schedule or the real-time lost opportunity cost economic operating point, less the operating profit at the scheduled quantity of energy for withdrawal given the real-time LMP or the export bid. (Select True or False)
   a) True
   b) False

14.1 Skill Check Two Answers

1. Intertie traders are subject to the IESO's Market Power Mitigation (MPM) framework as it relates to potential economic withholding on uncompetitive intertie zones. (Select True or False)

   a) True

   b) False

2. Which of the following tests are used by the IESO to identify instances of economic withholding of energy and operating reserve on uncompetitive interties?

   a) Conduct test and impact test

   b) Efficiency test and reliability test

   c) Supply test and demand test

   d) Price test and quantity test

3. Which of the following statements about congestion rents is correct?

   a) Congestion rents result from price differentials created by non-binding transmission constraints.

   b) Congestion rents occur when lower priced supply on one side of a constraint cannot fully serve demand on the other side, leading to higher priced supply serving the remaining demand.

   c) Congestion rents are unrelated to transmission constraints and are solely based on supply and demand.

   d) Congestion rents are collected only in the day-ahead market.

4. Imports are paid the price in the intertie zone while exports pay the price in the zone through which they are exporting.

   a) True

   b) False

5. Which components make up the Intertie Locational Marginal Price (LMP)?

   a) Reference Bus Component, Loss Component, and Internal Congestion Component

   b) Intertie Border Price (IBP) and Intertie Congestion Price (ICP)

   c) External Congestion Component and Net Interchange Scheduling Limit (NISL) Congestion Component

   d) All of the above

6. What is the Net Interchange Scheduling Limit (NISL) and why is it important?

   a) NISL is the maximum allowable flow limit for intertie transactions; it ensures Ontario resources can satisfy hour-to-hour ramping needs without adversely impacting reliability.

   b) NISL is the price paid for intertie transactions; it determines the cost of imports and exports.

   c) NISL is the total amount of energy scheduled for import and export; it balances the supply and demand in the Ontario market.

   d) NISL is the limit on the number of transactions that can be scheduled; it prevents market congestion.

7. The DAM Energy Balancing Credit for exports is calculated based on the operating profit given the real-time LMP and the lesser of the DAM schedule or the real-time lost opportunity cost economic operating point, less the operating profit at the scheduled quantity of energy for withdrawal given the real-time LMP or the export bid.

   a) True

   b) False

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linkedin.com/company/IESO

Connecting Today.
Powering Tomorrow.

Exhibit "W"

Email from Southwest Power Pool, Inc. (SPP) to Nexus Energy dated September 22, 2025

Exhibit "W"

to the Affidavit of Robin Doolittle

Sworn before me on October 29, 2025, in accordance with O. Reg. 431/20, Administering Oath or Declaration Remotely



Commissioner for Taking Affidavits
(or as may be)

October 29, 2025

Keith Edward Hickey, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.

Expires June 24, 2027.

_____>
Sent: September 22, 2025 10:42 AM
To: Erin Liu <erin.liu@nexusenergy.com>
Cc: Alvin Tang <alvin.tang@nexusenergy.com>; Francois Tardif <francois.tardif@nexusenergy.com>; Robin Doolittle <robin.doolittle@nexusenergy.com>; Nexus Accounting <accounting@nexusenergy.com>
Subject: RE: **External Email** SPP - Additional cash collateral

Some people who received this message don't often get email from credit@spp.org. Learn why this is important

Hello,

SPP is needing Nexus to maintain $200K as a minimum participation requirement for a minimum of three years. Being found in violation of market rules at another ISO/RTO, and being ordered to pay back $2.08MM is a serious issue that we agree should result in additional financial assurances. We understand you are closing the application to become a transmission customer. This requirement is valid as well to continue as a financial only entity with SPP.

Would you like SPP to hold part of the cash currently available or send are you going to send in more funds?

[redacted]
Credit Analysis
Southwest Power Pool, Inc.
201 Worthen Dr.
Little Rock, AR 72223
[redacted]

From: Erin Liu <erin.liu@nexusenergy.com>
Sent: Friday, September 19, 2025 1:35 PM
To: SPP Credit Department <credit@spp.org>
Cc: Alvin Tang <alvin.tang@nexusenergy.com>; Francois Tardif <francois.tardif@nexusenergy.com>; Robin Doolittle <robin.doolittle@nexusenergy.com>; Nexus Accounting <accounting@nexusenergy.com>
Subject: **External Email** SPP - Additional cash collateral

External email

STOP! This is **NOT** an SPP email.
Be very cautious of any links or attachments unless you recognize this sender and are expecting this email.
Please click the "Report Phish" button if you are unsure about this email.

Hello SPP Credit,

We've wired over $200,000 USD to increase our credit position, kindly confirm receipt of the funds at your earliest convenience.

	Debit Account	Credit Information	Value Date	Payment Amount	Status
1	[redacted] Operation USD	[redacted] USD-SOUTHWEST POWER POOL	Sep 19, 2025	200,000.00 USD	In Progress

Thank you,

nexus energy

Follow Us

Erin Liu
MANAGER, FINANCE & SETTLEMENTS

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Toronto, Ontario M2N 0G3
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erin.liu@nexusenergy.com
nexusenergy.com

This email is solely for the intended recipient and may contain confidential information. If you have received this email in error, please notify the sender immediately and delete the original message and all copies.

NEXUS ENERGY INC.	-and-	INDEPENDENT ELECTRICITY SYSTEM OPERATOR (IESO)
Applicant		Respondent

IN THE MATTER OF an Arbitration under Chapter 3 of the IESO Market Rules made pursuant to section 32 of the Ontario *Electricity Act, 1998*, S.O. 1998, c. 15, as amended

AFFIDAVIT OF ROBIN DOOLITTLE
AFFIRMED OCTOBER 29, 2025

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reena.goyal@blakes.com

Lawyers for the Applicant

TAB 3

IN THE MATTER OF an Arbitration under Chapter 3 of the IESO Market Rules made pursuant to section 32 of the Ontario *Electricity Act, 1998*, S.O. 1998, c. 15, as amended

B E T W E E N:

NEXUS ENERGY INC.

Applicant

- and -

INDEPENDENT ELECTRICITY SYSTEM OPERATOR (IESO)

Respondent

AFFIDAVIT OF FRANCOIS TARDIF

(AFFIRMED OCTOBER 29, 2025)

I, Francois Tardif, of the City of Vaughan, in the Province of Ontario, AFFIRM:

1. I am the Director of Risk and Regulatory Affairs and one of the first employees of Nexus Energy, the applicant in this proceeding and, as such, have knowledge of the matters contained in this affidavit unless otherwise specified. Prior to joining Nexus Energy, I worked as a power trader with Ontario Power Generation for 10 years. A copy of my curriculum vitae is attached to this affidavit as **Exhibit "A"**. Capitalized terms not otherwise defined herein have the meaning ascribed to them in the Affidavit of Robin Doolittle dated October 29, 2025 **("Robin Doolittle's Affidavit").**

IESO Notice of Alleged Breach

2. On April 4, 2024, Nexus Energy received a Notice of Alleged Breach from the IESO. The Notice of Alleged Breach stated that, among other things, the IESO has

"commenced an investigation into whether" Nexus Energy breached Chapter 7, section 7.5.8A of the IESO market rules for certain specified 1,661[1] energy trading (import and export) transactions ("**Subject Transactions**") conducted between December 28, 2017 and December 12, 2023 ("**Notice of Alleged Breach**"). A copy of the Notice of Alleged Breach is attached as **Exhibit "C"** to Robin Doolittle's Affidavit. The Notice of Alleged Breach is signed by Glenn McDonald, Vice-President of the IESO's Market Assessment and Compliance Division ("**MACD**").

3. The Notice of Alleged Breach states it was sent to Nexus Energy pursuant to Chapter 3, section 6.2.3 of the Market Rules. The Notice of Alleged Breach states that each of the Subject Transactions was a breach of Chapter 7, section 7.5.8A of the IESO Market Rules. A copy of each of Chapters 3 and 7 of the IESO Market Rules are attached as **Exhibits "L"** and **"M**", respectively, to Robin Doolittle's Affidavit**.**

4. Paragraph 13 of the Notice of Alleged Breach lists the following sources of evidence which purportedly informed MACD's basis for the Notice of Alleged Breach:

(i) IESO data indicating NEXUS energy bids and/or offers.

(ii) IESO control room logs.

(iii) E-Tag curtailment notifications to NEXUS.

(iv) Audio logs of the IESO's conversations with Nexus.

(v) IESO data indicating intertie schedules and failure reason codes.

(vi) OATI E-tag data.

[1] This number was subsequently reduced to 1,658 Subject Transactions in the Notice of Non-Compliance dated December 17, 2024.

None of this data was included with the Notice of Alleged Breach and much of it has otherwise never been provided to us by MACD. The importance of my concerns about MACD's lack of disclosure and data uncertainty are addressed in greater detail below.

5. The Notice of Alleged Breach also states in part at paragraph 8 that MACD had preliminarily assessed that Nexus Energy had "avoided congestion payments" in the total amount of $2,078,809. Under the subheading "Details of Possible Sanctions", the Notice of Alleged Breach states at paragraph 14 in part that "… MACD may issue one of the following sanctions: … pursuant to Chapter 3, section 6.6.10A.2 of the Market Rules, adjust settlement amounts, including avoided congestion rents …."

6. Prior to receiving the Notice of Alleged Breach in April 2024, we did not (to my knowledge) receive any notice from MACD of a potential compliance issue or investigation with respect to any of the Subject Transactions that spanned over more than the prior six years back to December 2017.

7. I was surprised to read the language in the IESO's Notice of Alleged Breach. Prior to receiving the Notice of Alleged Breach, I was unaware that energy trading market participants (like Nexus Energy) could be required to pay the IESO for congestion rents in relation to <u>failed</u> transactions. Prior to this dispute, my understanding was that congestion rents (what the IESO calls "the intertie congestion price or "**ICP**"[2]) is only

[2] Notice of Non-Compliance, paragraph 24.

calculated and payable for transactions that actually flow across the intertie, i.e. do not fail.

IESO Change in Position Prejudices Nexus Energy

8. Since Nexus Energy began participating in the IESO-administered markets in December 2017, our energy traders determined their trading bids/offers based in part on the understanding that there would be no compliance sanctions for transactions that fail for ordinary, non-market manipulation reasons.

9. More specifically, my understanding was that MACD would not be taking any compliance action for failed intertie transactions, other than the automated import failure charges ("**IFCs**") and export failure charges ("**EFCs**") described in Robin Doolittle's Affidavit, absent nefarious behaviour. And that the settlement amounts that could be readjusted or recovered by the IESO for failed intertie transactions would be limited to monies actually paid to market participants, such as transmission rights ("**TR"**) payments (which have been repaid to the IESO and are not in dispute).

10. To my knowledge, following the implementation of automated import IFCs and EFCs in 2006, as described in Robin Doolitte's Affidavit, there was no publicly reported compliance or enforcement action taken by MACD for almost 14 years (2006 to 2019) against any market participants with respect to intertie transaction failures, i.e. a breach of Chapter 7, section 7.5.8A of the Market Rules.

11. Based on the IESO webpages attached as **Exhibit "D"** to Robin Doolittle's Affidavit, it appears that MACD began taking compliance and enforcement action against

market participants for breaches of Chapter 7, section 7.5.8A of the Market Rules only in 2019.

12. Based on these webpages, there have been only three previous enforcement actions (one in each of 2019, 2020 and 2021) for failed intertie transactions. Nowhere on these IESO webpages have I seen that adjusted settlement amounts for a breach of Chapter 7, section 7.5.8A of the Market Rules include “avoided congestion rents” or ICP.

13. I had inferred from the IESO’s Compliance Enforcement webpage that the three summaries pertaining to failed intertie transactions (described as breaches of Chapter 7, section 7.5.8A of the Market Rules) involved the recovery of transmission rights payments and/or some form of nefarious behaviour such as intentional market manipulation or market abuse.

14. Moreover, because of the implementation of automated IFCs and EFCs in 2006, I had inferred that the summaries for breaches of Chapter 7, section 7.5.8A of the Market Rules, as described on the IESO’s Sanctions webpage and the IESO’s Negotiated Settlements webpage, pertained to the recovery of TR payments or other revenues actually received and as a result of untoward behaviour such as intentional market manipulation or market abuse.

15. To my knowledge, at no time prior to this dispute did the IESO publish any document or information to advise market participants of its interpretation that “avoided congestion rents” or avoided ICP could be sought by way of a settlement adjustment under Chapter 3, section 6.6.10A of the Market Rules. A copy of the webpage where

MACD publishes its Interpretation Bulletins and Statements of Approach, is attached to Robin Dollittle's Affidavit as **Exhibit "E"**.

16. If the IESO had the authority to seek "avoided congestion rents" for failed intertie transactions, I would have expected MACD to advise market participants by clearly publishing such information on its Interpretation Bulletins and Statements of Approach webpage or its Compliance Enforcement webpage. To my knowledge, IESO/MACD did not do this.

17. Had we known that failed transactions in the ordinary course of business could attract compliance sanctions for "avoided congestion rents", we would have structured our trading activities differently when we began trading in the IESO-administered markets in December 2017. For instance, part of the analysis that our energy traders would have undertaken in determining whether to place an intertie trade would have incorporated the cost of "avoided congestion rents" risk where the transaction could fail.

18. Moreover, had we been advised by MACD or the IESO prior to April 4, 2025 that any of the 1,658 Subject Transactions could be raising a non-compliance issue, I would have immediately discussed the matter with the rest of the leadership team for the purpose of modifying our trading behaviour.

19. In particular, had we been advised of any potential non-compliance prior to the 2021-2022 winter period, we would have changed our trading behaviour as needed and could have avoided almost half of the $2,078,809 in "avoided congestion rents" that are

the subject of this arbitration. For example, our energy traders would have elected not to submit bids/offers for some or many of the Subject Transactions, in whole or in part.

MACD's treatment of Nexus Energy's information requests

20. The Notice of Alleged Breach in April 2024 was a surprise and caused us great concern. We were eager to get an explanation from MACD and so we requested to meet with MACD to discuss the Notice of Alleged Breach, which meeting took place virtually (using Microsoft Teams) on April 12, 2024. I attended the April 12, 2024 meeting together with my former colleague from Nexus Energy, Ali Qaisar, and members of MACD including Robert (Bob) Yeoman.

21. At the meeting, we asked if and what opportunity we would have to review the evidence referred to in the Notice of Alleged Breach.

22. Following that meeting, we sent a follow-up email to MACD on May 6, 2024 seeking the following additional information so we could conduct our own analysis and provide a written response to the Notice of Alleged Breach:

> ● *The total export and import failure charges paid by Nexus*
>
> ● *When Ontario was contemporaneously experiencing surplus baseload conditions ("SBG")*
>
> ● *When Nexus was the sole marginal bidder that set the intertie congestion price ("ICP")*
>
> ● *The total number of failed MWs at the relevant interties during the hours covered by the list attached as the Appendix to the [Notice of Alleged Breach].*

23. I am advised by Ali Qaisar and believe that he spoke to Bob Yeoman of MACD by telephone on May 7, 2024 and was told that MACD was not required to respond to the information requests but would consider a reduced request for information because it would be too onerous for MACD to respond to all four of our information requests.

24. Accordingly, on May 8, 2024, we sent another email to MACD this time with reluctantly only two of our four initial information requests, as follows:

> *".. Data indicating whether Ontario was contemporaneously experiencing surplus baseload conditions (SBG) during any of the applicable hours listed in the appendix to MACD's notice.*
>
> *.. The total number of failed MWs at the relevant interties during the hours covered by the list attached as the Appendix to MACD's notice. Alternatively, if it would be less burdensome for MACD to provide historical reports for failures at the relevant interties (in anonymized format), Nexus can perform the necessary analysis to isolate the relevant hours on its own."*

A copy of the May 6 to 9, 2024 email exchange with MACD is attached as **Exhibit "B"** to this affidavit.

25. On June 25, 2024, MACD sent to us the SBG-related information for the entire December 2017 to December 2023 period (irrespective of whether there was a simultaneous failed Subject Transaction). What we had requested was information of when the IESO was experiencing SBG conditions <u>contemporaneous with the Subject Transactions</u>.

26. Accordingly, we had to sort through the data provided by the IESO against the period during which each of the Subject Transactions at issue occurred. Our analysis yielded several interesting facts.

27. First, the vast majority of the Subject Transactions related to failed exports out of Ontario, not imports. It would seem to me that, by their nature, failed import transactions would create more potential system reliability concerns as compared to failed export transactions. Based on our analysis, only slightly more than 100 (or about 6%) of the 1,658 Subject Transactions, totalling approximately 5,510 MWs, were import transactions into Ontario. The remaining 94% or so of the Subject Transactions, totalling approximately 105,239 MWs, pertained to electricity export transactions out of Ontario.

28. Second, it appears that the IESO was experiencing potential or actual surplus baseload generation ("**SBG**") conditions only during approximately 246 of the 1,658 Subject Transactions, i.e. less than 15% of the time. This means there were no SBG conditions in Ontario during more than 85% of the Subject Transactions for which Nexus Energy is being sanctioned by MACD. A copy of our analysis results based on the data provided to us by MACD on June 25, 2025, is attached as **Exhibit "C"**.

29. Third, based on our analysis of the data provided to us by MACD, it appears that during about half of our Subject Transactions other energy traders had also failed to flow their import/export transactions. Prior to this dispute, I was not aware of any other energy traders being investigated or charged by MACD for "avoided congestion rents" from failed intertie transactions during the same hours as the Subject Transactions.

Nexus Energy's Response

30. On July 9, 2024, we provided written submissions to MACD setting out Nexus Energy's responses to the Notice of Alleged Breach.

31. To my knowledge, nowhere in the Notice of Alleged Breach nor during MACD's investigation has it been suggested that Nexus Energy has acted nefariously, nor do I understand that IESO is taking that position in this arbitration.

32. Nexus Energy thereafter requested another meeting with MACD to discuss the breach allegations and again to seek an explanation. The meeting took place virtually (using Microsoft Teams) on September 4, 2024. I was at the meeting together with Ali Qaisar and Robin Doolittle, on behalf of Nexus Energy. The same MACD representatives were in attendance that had attended the April 12 meeting, including Bob Yeoman.

Notice of Non-Compliance and IESO Order

33. On December 17, 2024, Nexus Energy received the Notice of Non-Compliance with cover letter from MACD. The Notice of Non-Compliance is signed by Glenn McDonald. Copied on the Notice of Non-Compliance is Bob Yeoman, Director of "Rule Compliance and Market Surveillance, MACD". A copy of the Notice of Non-Compliance is attached as **Exhibit "F"** to Robin Doolittle's Affidavit.

34. Nexus Energy subsequently commenced the dispute resolution process under the IESO Market Rules to challenge the Notice of Non-Compliance and order requiring

payment of $2,078,809 for “avoided congestion rents”. A copy of Nexus Energy’s Notice of Dispute dated December 23, 2024 is attached as **Exhibit “D”**.

IESO fails to meaningfully participate in mediation

35. It was not until Nexus Energy filed its Amended Notice of Dispute on March 31, 2025 that MACD reached out to the Secretary of the IESO dispute resolution panel, namely the Honourable Mr. Frank Newbould, K.C., to request that a mediator be assigned. A copy of MACD’s April 1, 2025 email to Mr. Newbould is attached as **Exhibit “E”**. A copy of Nexus Energy’s Amended Notice of Dispute is attached as **Exhibit “F”**.

36. I am advised by Ali Qaisar and believe that following a conference call with the parties on April 9, 2025, Secretary Newbould agreed to act as a mediator for the dispute.

37. The mediation was held in Toronto on May 16, 2025, which Ali Qaisar and I together attended on behalf of Nexus Energy.

38. Also in attendance at the mediation were a number of MACD representatives, including Bob Yeoman and others that attended the April 12, 2024 and September 4, 2024 meetings. As far as I am aware, no one other than MACD representatives (and MACD’s external counsel) attended the mediation on behalf of the IESO. A copy of a MACD corporate organization chart that I am advised by Reena Goyal, counsel for Nexus Energy, and believe has been previously filed by the IESO with the Ontario Energy Board (“**OEB**”) is attached as **Exhibit “G”**.

39. The mediation began at approximately 9 a.m. and ended before 11 a.m., without a resolution. In my view, the MACD personnel in attendance at the mediation did not engage in a meaningful negotiation and appeared to be just 'going through the motions' to be able to say they completed the mediation stage of the dispute resolution process. A copy of Nexus Energy's further Amended Notice of Dispute dated May 21, 2025 is attached as **Exhibit "H"**.

Nexus Energy is also regulated by the Ontario Energy Board (OEB)

40. To participate in the IESO-administered markets, Nexus Energy is required to maintain an electricity wholesaler licence from the OEB. The OEB last issued an electricity wholesaler licence to Nexus Energy on September 13, 2022, pursuant to a licence renewal application I filed on behalf of Nexus Energy on June 17, 2022. A copy of that licence is attached as **Exhibit "I"**.

41. Based on the OEB's website, I understand that the OEB is "Ontario's independent regulator of the electricity and natural gas sectors". A printout of the OEB webpage from which I obtained this understanding, is attached as **Exhibit "J"**.

42. The OEB's website includes a webpage entitled "Market surveillance panel" ("**MSP**"). The MSP webpage states in part that the "Market Surveillance Panel monitors, investigates and reports on activities and behaviour in the IESO-administered markets in Ontario's electricity sector". The MSP webpage also says that "[u]nder the *Electricity Restructuring Act, 2004*, the Market Surveillance Panel transferred to the Ontario Energy

Board from the IESO, effective January 1, 2005." A copy of the MSP webpage is attached as **Exhibit "K"**.

43. The MSP webpage states in part that "[t]he mandate of the Panel [MSP] is set out in Ontario Energy Board By-Law #2 (pdf)". A copy of the document found at the weblink for that OEB By-Law #2 pdf is attached as **Exhibit "L"**. The MSP webpage also states in part that the OEB and the IESO "have entered into a Protocol (pdf)". A copy of the document found at the weblink for that Protocol pdf is attached as **Exhibit "M"**.

44. The MSP webpage includes a link to another OEB webpage entitled "Panel Reports". The last published MSP report released August 27, 2025, is attached as **Exhibit "N"**. The MSP webpage also includes the MSP Monitoring Report released on May 8, 2017, cited at footnote 8 of the Notice of Non-Compliance. A copy of that MSP report is attached as **Exhibit "O"**. The next MSP Monitoring Report released on March 22, 2018 is attached as **Exhibit "P"**.

45. Based on the MACD organizational chart attached as Exhibit G to this affidavit and the Notice of Non-Compliance, it appears that Bob Yeoman in his capacity as the Director of both Rule Compliance and Market Surveillance receives information pertaining to MSP-related activities while also a member of Rule Compliance. Likewise, it appears that Glenn McDonald, in his capacity as Vice-President of MACD and direct supervisor of Bob Yeoman, receives information pertaining to MSP-related activities.

AFFIRMED BEFORE ME by Francois Tardif, in the City of Vaughan, in the Province of Ontario before me at the City of Vaughan, in the Province of Ontario on October 29, 2025, in accordance with O. Reg 431/20, Administering Oath or Declaration Remotely.

Commissioner for Taking Affidavits
(or as may be)

Francois Tardif

October 29, 2025

Keith Edward Hickey, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.

Expires June 24, 2027.

Exhibit “A”

Curriculum Vitae of Mr. Francois Tardif

Exhibit “A”

to the Affidavit of Francois Tardif

Sworn before me on October 29, 2025, in accordance with O. Reg. 431/20,
Administering Oath or Declaration Remotely



Commissioner for Taking Affidavits
(or as may be)

October 29, 2025

Keith Edward Hickey, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.

Expires June 24, 2027.

A1665

FRANCOIS TARDIF

Director

FRANCOIS

CONTACT

647 381 5191

tardif.francois@gmail.com

Toronto, ON

LinkedIn

SKILLS

Risk Oversight
Strategy Development
Regulatory Compliance
Trading
Energy Markets
Client Outreach
Contract Negotiations
Green Strategies (Emissions, Environmental Impact)
Challenge Resolution
Business Development
Relationship Development
People Skills
Problem Solving
Communication
Team Leadership
Strategic Planning & Vision
Business Advisory

ENTREPRENEURSHIP

Cofounder, Nexus Energy

EDUCATION

Bachelor of Commerce in Finance
McGill University, Montreal, QC

PROFESSIONAL PROFILE

Empowering, passionate, and forward-thinking business leader with experience in the energy industry, recognised for the ability to apply analytical thinking, risk management, regulatory compliance, and operations oversight to achieve results. Possess expertise identifying, managing, and mitigating risks, while building consensus and identifying opportunities for growth. A people leader who steps up to new challenges with creativity and vision while able to make tough decisions. Solutions finder with a keen sense of the bigger picture. As a cofounder of Nexus Energy, I directly participated in the creation and growth of the company – from three employees at its inception, we are now at thirty and growing.

EXPERIENCE

Director, Risk & Regulatory Affairs / Risk Compliance Officer
Nexus Energy, Toronto, ON / 2022 - Present

- Lead the creation and oversight of required reports, risk policies, and procedures for the risk and regulatory affairs desk.
- Build and maintain understanding of current/upcoming market changes in various ISOs Nexus is a member of.
- Delivered guidance and input for the expansion of the company's retail operations including risk, regulatory, compliance oversight.
- Created/implemented training materials and facilitated on-going training for new hires.
- Confirmed compliance with internal/external laws, rules, and policies through continual monitoring.

Key Achievements:

- Established the risk/regulatory affairs desk to support overall company growth.
- Assisted in the creation and establishment of a West trading desk & office, including signing up for new ISOs (ERCOT & SPP) as well as adapting the risk policy & monitoring processes for the new markets
- Introduced monitoring processes and submitted required annual regulatory reporting.
- Created and released the company's Code of Conduct
- Supported and provided input on the recovery of positions that lost millions during several period of intense volatility in the energy markets through careful forecasting and risk management (objective thought processes). A more sophisticated risk policy was established based on lessons learned.
- Achieved sales team compliance with regulations, reviewing and approving contracts, establishing risk limits/parameters, and conducting credit checks.
- Assisted in introducing a new product offering to include Ontario Clean Energy Credits and CRS Renewable Energy Credits in response to a demand for products allowing companies to offset carbon emissions/promote renewable energy.
- Researched potential risks associated with green products, signed up with appropriate brokers and exchange houses, established credit and risk limits, and delivered initial annual audit reports.
- Developed/implemented an in-house training program for new hires.

CERTIFICATIONS

CFA Program – Level 1, CFA Institute

Canadian Securities Course

LANGUAGES SKILLS

Bilingual (English and French)

TECHNICAL SKILLS

Computer Skills, Basic Coding

BOARD EXPERIENCE

Board Director, Nexus Energy

- Led the execution of the signup process for regulatory bodies (eight Independent System Operators in Canada and the US, four governmental/quasi-governmental regulatory agencies (Canada and the US)) necessary for the company to conduct its business activities. This was a multi-month process requiring coordination with other investors/founders.
- Helped develop corporations' bylaws.
- Key driver in establishing the company's culture and vision.

EXPERIENCE *continued*

Director of Physical Trading
Nexus Energy, Toronto, ON / 2017 - 2022

- Completed sign-up process for required regulatory agencies and ISOs in Canada and the US (CAISO, OEB, NEB, FERC, IESO, ISONE, NYISO, MISO, PJM).
- Procured/sourced necessary credentials and software/services for real-time and short-term trading (certificates, deal capture system, ISO navigation/tagging software, and external data providers).
- Oversaw the performance of five real-time traders and held accountability for over 1GW of potential hourly market exposure (mix of real-time physical flows, day-ahead exposure in neighbouring markets backed by physical flows, financial & virtual positions, congestion products such as TRs)
- Led business development activities in the Hydro-Quebec and ISONE areas to identify origination-type deals selling power to HQ and procuring longer-term transmission for hedged transactions.
- Drafted and implemented training materials and guides for traders.
- Conducted proprietary trading daily encompassing day-ahead commitments and flows to neighbouring jurisdictions, virtual transactions, some speculative financial transactions, and hedging cleared transactions.

Key Achievements:

- Helped grow the company from three to 30+ employees
- Set up the real-time trading desk (developed policies, procedures, risk metrics, processes, tools, and training materials) and hired/trained senior and junior staff (five traders).

Affiliate Trader
Ontario Power Generation, Toronto, ON / 2007 - 2017

- Evaluated performance and managed/optimized OPG's trading positions by replacing real-time traders, when necessary, on shift rotations (non-standard hours).
- Analyzed benefits of and purchased long-term congestion products in Ontario and neighbouring jurisdictions (FTRs/TCCs/TRs)
- Completed detailed market analysis and identification of profitable trading opportunities using external/internal tools (web- and Excel-based).
- Directed speculative financial swaps and hedges on various exchanges.
- Delivered different projects including the creation of logistics packages detailing transaction guidelines for the US subsidiary and general training packages for new hires.
- Assessed/monitored daily risk limits and ensured adherence with these limits.
- Facilitated training for new hires and current employees.
- Planned and submitted generation into the day-ahead Ontario market as part of the Generation and Portfolio Management team.

Key Achievements:

- Developed and introduced short-term trading strategies across ISOs in the Northeast (MISO, IESO, PJM, NYISO, HQ, and NEISO).

Exhibit "B"

Email exchange between MACD and Nexus Energy dated May 6-9, 2024

Exhibit "B"

to the Affidavit of Francois Tardif

Sworn before me on October 29, 2025, in accordance with O. Reg. 431/20,
Administering Oath or Declaration Remotely



Commissioner for Taking Affidavits
(or as may be)

October 29, 2025

Keith Edward Hickey, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.

Expires June 24, 2027.

From: Bob Yeoman <Robert.Yeoman@ieso.ca>
Sent: Thursday, May 9, 2024 5:03 PM
To: Ali Qaisar <ali.qaisar@nexusenergycanada.com>
Cc: Francois Tardif <francois.tardif@nexusenergycanada.com>; MACD Inbox <MACDInbox@ieso.ca>; Egor Sitnik <Egor.Sitnik@ieso.ca>; Bob Yeoman <Robert.Yeoman@ieso.ca>
Subject: RE: Request for a meeting regarding case COM237240

Hi Ali,

The below request is noted and under consideration. The original deadline of May 10 will be extended and a new deadline can be established when MACD provides its response to the below.

Thank you,

Bob

Bob Yeoman | Sr. Manager, Rule Enforcement | Market Assessment and Compliance Division | T: (905) 855-6175 | C: (905) 330-4094

From: Ali Qaisar <ali.qaisar@nexusenergycanada.com>
Sent: May 8, 2024 1:46 PM
To: Bob Yeoman <Robert.Yeoman@ieso.ca>
Cc: Francois Tardif <francois.tardif@nexusenergycanada.com>; MACD Inbox <MACDInbox@ieso.ca>; Egor Sitnik <Egor.Sitnik@ieso.ca>
Subject: RE: Request for a meeting regarding case COM237240

CAUTION: This email originated from outside of the organization. Exercise caution when clicking on links or opening attachments even if you recognize the sender.

Hi Bob,

Thanks for taking the time to speak to us yesterday. Further to our conversation, I have had discussions with our team regarding the possibility of narrowing down the data requests or submitting our preliminary response prior to receipt of the requested data. The team is not in a position to finalize a preliminary response without any of the requested data, but has indicated that they could provide a response upon receipt of more limited data, on the understanding that further data could be requested at the time of, or subsequent to, submitting our initial response. Below is our narrowed-down request for data at this time:

1. 1. Data indicating whether Ontario was contemporaneously experiencing surplus baseload conditions (SBG) during any of the applicable hours listed in the appendix to MACD's notice.

2. 2. The total number of failed MWs at the relevant interties during the hours covered by the list attached as the Appendix to MACD's notice. Alternatively, if it would be less burdensome for MACD to provide historical reports for failures at the relevant interties (in anonymized format), Nexus can perform the necessary analysis to isolate the relevant hours on its own.

We would ask that the deadline to submit our initial representations be extended so that we have a reasonable time following the receipt of the above data from MACD to complete our analysis and submit our response.

Kind regards,

Ali Qaisar
General Counsel
+1 437-238-6128
Nexus Energy
POWER WITHOUT BORDERS

From: Bob Yeoman <Robert.Yeoman@ieso.ca>
Sent: Monday, May 6, 2024 4:43 PM
To: Ali Qaisar <ali.qaisar@nexusenergycanada.com>
Cc: Francois Tardif <francois.tardif@nexusenergycanada.com>; MACD Inbox <MACDInbox@ieso.ca>; Egor Sitnik <Egor.Sitnik@ieso.ca>; Bob Yeoman <Robert.Yeoman@ieso.ca>
Subject: RE: Request for a meeting regarding case COM237240

Hi Ali,

Are you available for a quick call tomorrow on the below request?

Thanks,

Bob

Bob Yeoman | Sr. Manager, Rule Enforcement | Market Assessment and Compliance Division | T: (905) 855-6175 | C: (905) 330-4094

From: Ali Qaisar <ali.qaisar@nexusenergycanada.com>
Sent: May 6, 2024 1:43 PM
To: Bob Yeoman <Robert.Yeoman@ieso.ca>
Cc: Francois Tardif <francois.tardif@nexusenergycanada.com>; MACD Inbox <MACDInbox@ieso.ca>; Egor Sitnik <Egor.Sitnik@ieso.ca>
Subject: RE: Request for a meeting regarding case COM237240

CAUTION: This email originated from outside of the organization. Exercise caution when clicking on links or opening attachments even if you recognize the sender.

Hi Bob,

Thank you again for meeting with us on April 12th.

In an attempt to resolve this matter as expeditiously as possible, we are in the process of internally preparing our own analysis for the subject transactions listed in Appendix A of the April 4 notice. Can you please provide the following additional information in respect of the subject transactions:

- * The total export and import failure charges paid by Nexus
- * When Ontario was contemporaneously experiencing surplus baseload conditions (SBG)
- * When Nexus was the sole marginal bidder that set the intertie congestion price (ICP)
- * The total number of failed MWs at the relevant interties during the hours covered by the list attached as the Appendix to MACD's notice.

Once we receive this information, we would appreciate an opportunity to meet with you again to discuss potential early resolution. We would ask that the deadline for submission of our written representations be extended to a date that allows for the receipt of the above information from MACD and a further meeting prior to submission. Thank you.

Kind regards,

Ali Qaisar
General Counsel
+1 437-238-6128
Nexus Energy
POWER WITHOUT BORDERS

Exhibit “C”

Surplus baseload generation (SBG) data analysis

Exhibit “C”

to the Affidavit of Francois Tardif

Sworn before me on October 29, 2025, in accordance with O. Reg. 431/20, Administering Oath or Declaration Remotely



Commissioner for Taking Affidavits
(or as may be)

October 29, 2025

Keith Edward Hickey, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.

Expires June 24, 2027.

5/12/2018	17	NY.ROSETON.SINK.01	NYSI	-125	-25	13.22	-25	0 SBG
5/13/2018	16	NY.ROSETON.SINK.01	NYSI	-125	-25	10.83	-75	0 SBG
5/20/2018	1	NY.ROSETON.SINK.02	NYSI	-102	-2	2.47	-2	0 SBG
5/21/2018	7	NY.ROSETON.SINK.02	NYSI	-25	-25	16.42	-25	0 SBG
5/21/2018	8	NY.ROSETON.SINK.02	NYSI	-25	-25	12.39	-25	0 SBG
5/21/2018	9	NY.ROSETON.SINK.01	NYSI	-100	-57	22.22	-225	0 SBG
5/21/2018	11	NY.ROSETON.SINK.01	NYSI	-100	-30	29.25	-30	0 SBG
5/22/2018	1	NY.ROSETON.SINK.02	NYSI	-60	-60	9.51	-60	0 SBG
5/22/2018	2	NY.ROSETON.SINK.02	NYSI	-40	-20	3	-21	0 SBG
5/22/2018	4	NY.ROSETON.SINK.02	NYSI	-60	-60	0.14	-60	0 SBG
5/27/2018	5	NY.ROSETON.SINK.02	NYSI	-36	-36	0.66	-36	0 SBG
6/21/2018	1	NY.ROSETON.SINK.02	NYSI	-100	-100	9.68	-100	0 SBG
6/25/2018	2	NY.ROSETON.SINK.02	NYSI	-100	-100	2.49	-100	0 SBG
7/8/2018	3	MI.LUDINGTON.SINK.(	MISI	-50	-50	13.52	-50	0 SBG
7/19/2018	4	NY.ROSETON.SINK.02	NYSI	-200	-200	1	-200	0 SBG
7/22/2018	3	NY.ROSETON.SINK.02	NYSI	-50	-25	8.49	-25	0 SBG
8/9/2018	1	NY.ROSETON.SINK.02	NYSI	-250	-150	3.98	-150	0 SBG
8/23/2018	4	NY.ROSETON.SINK.03	NYSI	-10	-10	10	-10	0 SBG
9/8/2018	5	NY.ROSETON.SINK.02	NYSI	-43	-43	20.47	-43	0 SBG
9/9/2018	1	MI.LUDINGTON.SINK.(	MISI	-25	-25	20.17	-90	0 SBG
9/9/2018	2	NY.ROSETON.SINK.02	NYSI	-25	-25	19.5	-25	0 SBG
9/9/2018	2	MI.LUDINGTON.SINK.(	MISI	-25	-25	22.47	-90	0 SBG
9/9/2018	3	NY.ROSETON.SINK.02	NYSI	-25	-25	23	-25	0 SBG
9/9/2018	4	NY.ROSETON.SINK.02	NYSI	-25	-25	24	-25	0 SBG
9/10/2018	1	MI.LUDINGTON.SINK.(	MISI	-25	-25	20.33	-25	0 SBG
9/12/2018	14	MI.LUDINGTON.SINK.(	MISI	-25	-25	20.41	-50	0 SBG
9/12/2018	14	MD.CALVERTCLIFF.SI	MISI	-25	-25	20.41	-50	0 SBG
9/20/2018	3	MB.WHITESHELL.US.S	MBSI	-50	-50	2.55	-65	0 SBG
9/20/2018	3	MI.LUDINGTON.SINK.(	MISI	-100	-100	7.13	-100	0 SBG
9/21/2018	3	NY.ROSETON.SINK.02	NYSI	-50	-50	14.65	-50	0 SBG
9/22/2018	24	MI.LUDINGTON.SINK.(	MISI	-20	-20	16.15	-20	0 SBG
9/24/2018	1	MB.WHITESHELL.US.S	MBSI	-50	-9	20.81	-9	0 SBG
9/24/2018	2	NY.ROSETON.SINK.02	NYSI	-25	-25	14.74	-45	0 SBG
9/24/2018	2	MI.LUDINGTON.SINK.(	MISI	-25	-25	20.36	-28	0 SBG
9/27/2018	23	MI.LUDINGTON.SINK.2	MISI	-50	-50	1.65	-50	0 SBG
9/30/2018	5	MB.WHITESHELL.US.S	MBSI	-50	-50	44.06	-50	0 SBG
10/1/2018	2	MI.LUDINGTON.SINK.(	MISI	-25	-25	15.81	-25	0 SBG
10/1/2018	3	MI.LUDINGTON.SINK.(	MISI	-25	-25	22	-25	0 SBG
10/1/2018	3	MB.WHITESHELL.US.S	MBSI	-33	-33	71.94	-58	0 SBG
10/1/2018	4	MI.LUDINGTON.SINK.(	MISI	-3	-3	22.87	-3	0 SBG
10/3/2018	1	MI.LUDINGTON.SINK.(	MISI	-39	-39	26.12	-39	0 SBG
10/6/2018	1	MD.CALVERTCLIFF.SI	MISI	-50	-50	24.42	-50	0 SBG
10/6/2018	3	MB.WHITESHELL.CAN	MBSI	1	1	33.83	0	1 SBG
10/7/2018	7	MI.LUDINGTON.SINK.(	MISI	-25	-25	21.77	-25	0 SBG
10/8/2018	3	MI.LUDINGTON.SINK.(	MISI	-25	-25	33.2	-25	0 SBG
10/8/2018	4	NY.ROSETON.SINK.02	NYSI	-25	-25	24.2	-25	0 SBG
10/8/2018	4	MI.LUDINGTON.SINK.(	MISI	-25	-25	39.2	-25	0 SBG
10/8/2018	5	MI.LUDINGTON.SINK.(	MISI	-25	-25	39.2	-25	0 SBG
10/8/2018	8	MB.WHITESHELL.US.S	MBSI	-50	-50	15	-50	3 SBG
10/9/2018	1	MD.CALVERTCLIFF.SI	MISI	-25	-25	33	-25	0 SBG
10/9/2018	3	MI.LUDINGTON.SINK.(	MISI	-25	-25	31.2	-25	0 SBG
########	1	MB.WHITESHELL.US.S	MBSI	-9	-9	45	-9	0 SBG
########	2	NY.ROSETON.SINK.02	NYSI	-50	-50	16.78	-50	0 SBG
########	3	MB.WHITESHELL.US.S	MBSI	-9	-9	45	-9	0 SBG
########	2	NY.ROSETON.SINK.25	NYSI	-19	-19	7.1	-19	0 SBG
########	4	MB.WHITESHELL.US.S	MBSI	-43	-43	75.06	-43	0 SBG
########	5	MB.WHITESHELL.US.S	MBSI	-43	-43	43	-43	0 SBG
########	6	MB.WHITESHELL.US.S	MBSI	-33	-33	43	-33	0 SBG
########	1	MB.WHITESHELL.US.S	MBSI	-50	-50	34	-50	0 SBG
########	2	MB.WHITESHELL.US.S	MBSI	-50	-50	34.1	-50	0 SBG
########	3	MB.WHITESHELL.US.S	MBSI	-15	-15	30.25	-15	0 SBG
11/6/2018	2	MB.WHITESHELL.US.S	MBSI	-48	-48	18.5	-48	0 SBG
12/2/2018	1	MB.WHITESHELL.US.S	MBSI	-66	-66	25.56	-66	0 SBG
12/2/2018	1	MD.CALVERTCLIFF.SI	MISI	-35	-35	31.88	-35	0 SBG
12/2/2018	2	MB.WHITESHELL.US.S	MBSI	-66	-66	75	-66	0 SBG
12/2/2018	4	MB.WHITESHELL.US.S	MBSI	-49	-49	68.94	-69	0 SBG
12/2/2018	4	MB.WHITESHELL.US.S	MBSI	-20	-20	68.94	-69	0 SBG
12/2/2018	5	MB.WHITESHELL.US.S	MBSI	-49	-49	25	-49	0 SBG
12/2/2018	6	MB.WHITESHELL.US.S	MBSI	-49	-49	25	-49	0 SBG
########	4	MD.CALVERTCLIFF.SI	MISI	-100	-100	18.19	-100	0 SBG
1/1/2019	2	MB.WHITESHELL.US.S	MBSI	-50	-50	51.16	-50	0 SBG
1/1/2019	9	MI.LUDINGTON.SINK.(	MISI	-1	-1	22.56	-1	0 SBG
5/19/2019	2	MN.INTFALLS.US.SINK	MNSI	-4	-4	17.18	-4	0 SBG
5/20/2019	9	NY.ROSETON.SINK.04	NYSI	-50	-50	13.12	-50	0 SBG
5/20/2019	10	NY.ROSETON.SINK.04	NYSI	-50	-50	3.46	-50	0 SBG
5/24/2019	6	MI.LUDINGTON.SINK.(	MISI	-50	-50	26.09	-50	0 SBG
5/25/2019	2	NY.ROSETON.SINK.01	NYSI	-50	-50	1.99	-235	0 SBG
5/25/2019	3	NY.ROSETON.SINK.25	NYSI	-47	-47	5.11	-47	0 SBG
5/26/2019	1	NY.ROSETON.SINK.25	NYSI	-50	-50	7.7	-50	0 SBG
5/26/2019	15	MN.INTFALLS.US.SINK	MNSI	-6	-6	13.18	-6	0 SBG
5/27/2019	1	NY.ROSETON.SINK.25	NYSI	-50	-50	6.2	-650	0 SBG
5/28/2019	4	NY.ROSETON.SINK.25	NYSI	-50	-15	16.4	-40	0 SBG
5/28/2019	4	NY.ROSETON.SINK.03	NYSI	-25	-25	16.4	-40	0 SBG
5/28/2019	23	NY.ROSETON.SINK.03	NYSI	-25	-25	20	-25	0 SBG
5/29/2019	4	MB.WHITESHELL.US.S	MBSI	-34	-34	21.75	-34	0 SBG
5/30/2019	1	MI.LUDINGTON.SINK.(	MISI	-1	-1	26.9	-1	0 SBG
6/1/2019	15	NY.ROSETON.SINK.01	NYSI	-100	-100	17	-275	0 SBG
6/2/2019	11	NY.ROSETON.SINK.05	NYSI	-50	-49	1.99	-533	0 SBG
6/2/2019	11	MD.CALVERTCLIFF.SI	MISI	-25	-25	1.99	-533	0 SBG
6/2/2019	13	NY.ROSETON.SINK.25	NYSI	-25	-15	8.1	-15	0 SBG
6/2/2019	16	NY.ROSETON.SINK.05	NYSI	-50	-50	14.17	-100	0 SBG
6/2/2019	17	NY.ROSETON.SINK.05	NYSI	-25	-25	13.33	-25	0 SBG
6/5/2019	2	NY.ROSETON.SINK.05	NYSI	-10	-10	22.49	-10	0 SBG
6/6/2019	21	NY.ROSETON.SINK.05	NYSI	-25	-20	11.54	-245	0 SBG
6/6/2019	23	NY.ROSETON.SINK.05	NYSI	-25	-25	20	-25	0 SBG
6/7/2019	1	NY.ROSETON.SINK.05	NYSI	-50	-50	22.2	-50	0 SBG
6/7/2019	2	NY.ROSETON.SINK.05	NYSI	-50	-25	18.3	-25	0 SBG
6/7/2019	3	NY.ROSETON.SINK.05	NYSI	-25	-25	18.4	-25	0 SBG
6/9/2019	14	NY.ROSETON.SINK.25	NYSI	-25	-25	3.5	-25	0 SBG
6/9/2019	15	NY.ROSETON.SINK.25	NYSI	-25	-25	8.5	-25	0 SBG
6/12/2019	16	NY.ROSETON.SINK.25	NYSI	-50	-25	2.01	-25	0 SBG

6/13/2019	6	NY.ROSETON.SINK.01	NYSI	-150	-150	15.16	-150	0 SBG
6/13/2019	12	NY.ROSETON.SINK.2E	NYSI	-25	-25	9.48	-25	0 SBG
6/14/2019	9	NY.ROSETON.SINK.2E	NYSI	-50	-20	6.33	-20	0 SBG
6/14/2019	10	NY.ROSETON.SINK.2E	NYSI	-50	-50	6.17	-50	0 SBG
6/14/2019	12	NY.ROSETON.SINK.2E	NYSI	-20	-20	3.49	-110	0 SBG
6/14/2019	22	NY.ROSETON.SINK.2E	NYSI	-25	-25	9.8	-25	0 SBG
6/15/2019	14	NY.ROSETON.SINK.03	NYSI	-40	-40	6.5	-500	0 SBG
6/15/2019	20	NY.ROSETON.SINK.2E	NYSI	-35	-35	5.5	-35	0 SBG
6/17/2019	5	NY.ROSETON.SINK.2E	NYSI	-50	-50	5.11	-50	0 SBG
6/22/2019	6	MB.WHITESHELL.US.S	MBSI	-50	-7	19	-7	0 SBG
6/23/2019	14	NY.ROSETON.SINK.0E	NYSI	-82	-82	1.53	-299	0 SBG
6/26/2019	3	NY.ROSETON.SINK.2E	NYSI	-50	-25	1.52	-100	0 SBG
6/26/2019	4	NY.ROSETON.SINK.0E	NYSI	-43	-43	0.52	-100	0 SBG
6/29/2019	22	MB.WHITESHELL.US.S	MBSI	-50	-50	12.72	-50	0 SBG
7/7/2019	3	NY.ROSETON.SINK.03	NYSI	-35	-35	25	-35	0 SBG
7/7/2019	4	NY.ROSETON.SINK.2E	NYSI	-50	-15	24.1	-15	0 SBG
7/9/2019	6	MI.LUDINGTON.SINK.(	MISI	-50	-50	20.29	-50	0 SBG
7/11/2019	3	NY.ROSETON.SINK.04	NYSI	-138	-11	20.88	-11	0 SBG
7/11/2019	3	MI.LUDINGTON.SINK.(	MISI	-54	-1	31.12	-51	0 SBG
7/13/2019	5	MD.CALVERTCLIFF.SI	NYSI	-6	-6	1	-6	0 SBG
7/15/2019	2	NY.ROSETON.SINK.01	NYSI	-100	-25	2.48	-25	0 SBG
7/24/2019	3	NY.ROSETON.SINK.01	NYSI	-50	-50	9.45	-50	0 SBG
7/24/2019	5	MB.WHITESHELL.US.S	MBSI	-33	-33	1	-33	0 SBG
8/6/2019	3	NY.ROSETON.SINK.03	NYSI	-24	-24	17.12	-24	0 SBG
8/7/2019	2	NY.ROSETON.SINK.03	NYSI	-30	-30	3.6	-30	0 SBG
8/9/2019	4	NY.ROSETON.SINK.02	NYSI	-26	-26	19.02	-26	0 SBG
8/16/2019	9	NY.ROSETON.SINK.02	NYSI	-66	-66	4.61	-66	0 SBG
8/18/2019	8	NY.ROSETON.SINK.02	NYSI	-28	-28	2.61	-28	0 SBG
8/20/2019	1	MN.INTFALLS.US.SINK	MNSI	-20	-20	36.02	-20	0 SBG
8/23/2019	7	NY.ROSETON.SINK.01	NYSI	-91	-91	6.25	-91	0 SBG
8/25/2019	6	MN.INTFALLS.US.SOL	MNSI	2	2	15.55	0	2 SBG
8/26/2019	2	NY.ROSETON.SINK.03	NYSI	-16	-16	13.56	-16	0 SBG
8/26/2019	4	NY.ROSETON.SINK.03	NYSI	-16	-16	10.56	-16	0 SBG
8/31/2019	7	NY.ROSETON.SINK.04	NYSI	-41	-41	10.79	-41	0 SBG
9/1/2019	3	MB.WHITESHELL.US.S	MBSI	-68	-68	3.1	-68	0 SBG
9/1/2019	4	NY.ROSETON.SINK.01	NYSI	-48	-48	6.3	-48	0 SBG
9/1/2019	4	MB.WHITESHELL.US.S	MBSI	-68	-68	2.75	-68	0 SBG
9/2/2019	5	MB.WHITESHELL.US.S	MBSI	-68	-6	3.15	-6	0 SBG
9/8/2019	10	MB.WHITESHELL.US.S	MBSI	-68	-68	37.25	-68	0 SBG
9/8/2019	13	NY.ROSETON.SINK.01	NYSI	-35	-35	1.02	-35	0 SBG
9/14/2019	4	NY.ROSETON.SINK.0E	NYSI	-50	-25	10	-25	0 SBG
9/14/2019	5	NY.ROSETON.SINK.0E	NYSI	-50	-25	7	-25	0 SBG
9/14/2019	6	NY.ROSETON.SINK.0E	NYSI	-50	-25	12	-25	0 SBG
9/14/2019	7	NY.ROSETON.SINK.0E	NYSI	-50	-25	12	-25	0 SBG
9/19/2019	3	NY.ROSETON.SINK.01	NYSI	-96	-46	1.54	-46	0 SBG
9/19/2019	4	MB.WHITESHELL.US.S	MBSI	-50	-50	15.1	-50	0 SBG
10/7/2019	1	NY.ROSETON.SOURC	NYSI	10	10	14	-10	10 SBG
########	4	NY.ROSETON.SINK.01	NYSI	-25	-25	3.99	-25	0 SBG
########	5	NY.ROSETON.SINK.01	NYSI	-8	-8	3.24	-8	0 SBG
########	6	NY.ROSETON.SINK.01	NYSI	-25	-25	1.24	-25	0 SBG
########	1	MN.INTFALLS.US.SINK	MNSI	-60	-60	6.8	-60	0 SBG
########	8	NY.ROSETON.SINK.02	NYSI	-100	-75	7.38	-75	0 SBG
########	8	NY.ROSETON.SINK.02	NYSI	-50	-50	10.72	-50	0 SBG
########	2	NY.ROSETON.SINK.01	NYSI	-90	-15	20.5	-15	0 SBG
########	22	NY.ROSETON.SINK.01	NYSI	-54	-54	11.12	-54	0 SBG
########	24	NY.ROSETON.SINK.01	NYSI	-38	-38	6.44	-38	0 SBG
########	2	NY.ROSETON.SINK.01	NYSI	-15	-15	0.51	-15	0 SBG
########	11	MD.CALVERTCLIFF.SI	NYSI	-25	-25	13.98	-25	0 SBG
########	15	NY.ROSETON.SOURC	NYSI	25	25	10.23	-25	25 SBG
########	16	NY.ROSETON.SOURC	NYSI	25	25	14.43	-25	25 SBG
########	2	NY.ROSETON.SINK.02	NYSI	-50	-50	15	-50	0 SBG
########	8	NY.ROSETON.SINK.02	NYSI	-45	-45	11.88	-45	0 SBG
########	3	MB.WHITESHELL.US.S	MBSI	-68	-6	4.41	-6	0 SBG
12/8/2019	3	NY.ROSETON.SINK.04	NYSI	-157	-100	12.9	-100	0 SBG
12/8/2019	7	NY.ROSETON.SINK.04	NYSI	-50	-50	5.26	-50	0 SBG
1/1/2020	1	NY.ROSETON.SINK.0E	NYSI	-27	-27	9.51	-27	0 SBG
1/1/2020	12	NY.ROSETON.SINK.03	NYSI	-75	-75	6.76	-100	0 SBG
1/1/2020	12	NY.ROSETON.SINK.2E	NYSI	-50	-25	6.76	-100	0 SBG
1/3/2020	1	NY.ROSETON.SINK.03	NYSI	-49	-49	3.79	-69	0 SBG
1/3/2020	1	NY.ROSETON.SINK.2E	NYSI	-50	-20	3.79	-69	0 SBG
1/12/2020	4	MI.LUDINGTON.SINK.(	MISI	-100	-100	14.6	-100	0 SBG
2/22/2020	2	NY.ROSETON.SINK.03	NYSI	-50	-50	3.44	-50	0 SBG
2/23/2020	3	NY.ROSETON.SINK.2E	NYSI	-25	-25	1.16	-44	0 SBG
2/23/2020	3	NY.ROSETON.SINK.03	NYSI	-19	-19	1.16	-44	0 SBG
3/27/2020	15	MN.INTFALLS.US.SINK	MNSI	-13	-13	1.26	-13	0 SBG
4/11/2020	3	NY.ROSETON.SINK.0E	NYSI	-50	-25	9.5	-100	0 SBG
4/13/2020	1	NY.ROSETON.SINK.03	NYSI	-75	-25	0.51	-64	0 SBG
4/26/2020	7	NY.ROSETON.SINK.04	NYSI	-200	-200	4.2	-200	0 SBG
4/26/2020	8	NY.ROSETON.SINK.04	NYSI	-200	-121	1	-171	0 SBG
4/30/2020	2	NY.ROSETON.SINK.0E	NYSI	-150	-50	0.01	-50	0 SBG
4/30/2020	4	MI.LUDINGTON.SINK.(	MISI	-75	-75	3.22	-75	0 SBG
5/3/2020	13	NY.ROSETON.SINK.01	NYSI	-100	-96	2	-96	0 SBG
5/4/2020	1	NY.ROSETON.SINK.02	NYSI	-43	-43	0.26	-243	0 SBG
5/17/2020	8	NY.ROSETON.SINK.04	NYSI	-130	-1	9.66	-5	0 SBG
5/24/2020	7	NY.ROSETON.SINK.02	NYSI	-100	-25	2.22	-25	0 SBG
6/1/2020	2	NY.ROSETON.SINK.03	NYSI	-44	-44	4.99	-44	0 SBG
6/3/2020	4	MB.WHITESHELL.US.S	MBSI	-34	-34	8.5	-34	0 SBG
6/3/2020	4	NY.ROSETON.SINK.02	NYSI	-100	-20	6.12	-20	0 SBG
6/4/2020	3	NY.ROSETON.SINK.02	NYSI	-150	-25	0.99	-25	0 SBG
6/9/2020	2	NY.ROSETON.SINK.01	NYSI	-100	-100	6.8	-100	0 SBG
6/9/2020	3	MB.WHITESHELL.US.S	MBSI	-68	-68	8.57	-68	0 SBG
6/13/2020	2	NY.ROSETON.SINK.02	NYSI	-88	-38	7.33	-38	0 SBG
6/13/2020	4	NY.ROSETON.SINK.02	NYSI	-101	-26	6.18	-26	0 SBG
6/13/2020	24	NY.ROSETON.SINK.02	NYSI	-100	-25	2.01	-25	0 SBG
6/14/2020	1	NY.ROSETON.SINK.02	NYSI	-100	-100	0.99	-100	0 SBG
6/15/2020	1	NY.ROSETON.SINK.04	NYSI	-200	-46	3	-46	0 SBG
6/15/2020	4	NY.ROSETON.SINK.04	NYSI	-153	-153	0.01	-153	0 SBG
6/24/2020	1	NY.ROSETON.SINK.2E	NYSI	-46	-46	15	-96	0 SBG
6/25/2020	1	NY.ROSETON.SINK.04	NYSI	-121	-121	6.11	-121	0 SBG
6/28/2020	1	MI.LUDINGTON.SINK.(	MISI	-71	-71	8.71	-71	0 SBG
7/6/2020	4	NY.ROSETON.SINK.04	NYSI	-75	-75	0.57	-75	0 SBG

7/22/2020	3	NY.ROSETON.SINK.0:	NYSI	-50	-50	8	-50	0 SBG
7/22/2020	5	NY.ROSETON.SINK.0:	NYSI	-54	-54	8.26	-54	0 SBG
8/4/2020	2	NY.ROSETON.SINK.04	NYSI	-155	-155	10.31	-155	0 SBG
8/30/2020	2	MI.LUDINGTON.SINK.(	MISI	-50	-50	15.4	-50	0 SBG
8/30/2020	4	NY.ROSETON.SINK.0:	NYSI	-137	-87	13.99	-87	0 SBG
8/30/2020	6	NY.ROSETON.SINK.0:	NYSI	-200	-150	10.8	-150	0 SBG
9/30/2020	4	NY.ROSETON.SINK.0:	NYSI	-100	-100	2.85	-100	0 SBG
########	7	NY.ROSETON.SINK.22	NYSI	-25	-25	0.7	-250	0 SBG
########	3	NY.ROSETON.SINK.0:	NYSI	-130	-5	1.51	-5	0 SBG
########	4	NY.ROSETON.SINK.0:	NYSI	-178	-178	0.71	-178	0 SBG
########	6	NY.ROSETON.SINK.0:	NYSI	-50	-50	5	-50	0 SBG
4/25/2021	18	MB.WHITESHELL.US.!	MBSI	-68	-1	14.35	-1	0 SBG
4/28/2021	4	MB.WHITESHELL.US.!	MBSI	-68	-19	12.1	-19	0 SBG
5/1/2021	24	MB.WHITESHELL.US.!	MBSI	-50	-2	26.29	-50	0 SBG
5/2/2021	10	MN.INTFALLS.US.SOL	MNSI	21	21	14.66	0	21 SBG
5/25/2021	2	NY.ROSETON.SINK.0:	NYSI	-50	-50	1	-50	0 SBG
5/25/2021	3	NY.ROSETON.SINK.0:	NYSI	-35	-35	0.01	-126	0 SBG
7/11/2021	4	NY.ROSETON.SINK.01	NYSI	-75	-75	4.6	-75	0 SBG
8/2/2021	10	MI.LUDINGTON.SINK.(	MISI	-25	-25	5.38	-25	0 SBG
9/26/2021	4	NY.ROSETON.SINK.02	NYSI	-168	-168	3	-174	0 SBG
9/26/2021	5	NY.ROSETON.SINK.02	NYSI	-150	-150	41.2	-218	0 SBG
4/25/2022	3	NY.ROSETON.SINK.02	NYSI	-85	-85	0.02	-107	0 SBG
5/1/2022	10	NY.ROSETON.SINK.02	NYSI	-23	-23	1.21	-27	0 SBG
5/1/2022	11	NY.ROSETON.SINK.02	NYSI	-39	-39	1.3	-50	0 SBG
5/7/2022	1	NY.ROSETON.SINK.04	NYSI	-100	-100	8.2	-120	0 SBG
5/7/2022	2	NY.ROSETON.SINK.04	NYSI	-150	-41	1.21	-41	0 SBG
5/7/2022	4	NY.ROSETON.SINK.04	NYSI	-139	-139	2.35	-157	0 SBG
5/8/2022	15	MD.CALVERTCLIFF.SI	MISI	-25	-25	62.22	-25	0 SBG
5/22/2022	7	MB.WHITESHELL.US.!	MBSI	-102	-102	103.42	-102	0 SBG
5/29/2022	5	NY.ROSETON.SINK.01	NYSI	-60	-60	46.5	-71	0 SBG
6/2/2022	5	MB.WHITESHELL.US.!	MBSI	-50	-50	26.26	-50	0 SBG
6/2/2022	5	NY.ROSETON.SINK.0:	NYSI	-15	-15	60.53	-15	0 SBG
6/2/2022	5	MI.LUDINGTON.SINK.(	MISI	-25	-25	63.17	-25	0 SBG
6/4/2022	2	NY.ROSETON.SINK.02	NYSI	-50	-31	66.88	-46	0 SBG
6/4/2022	3	PQ.OUTAOUAIS.SINK.	PQAT	-300	-300	25	-338	0 SBG
6/4/2022	7	NY.ROSETON.SINK.02	NYSI	-15	-15	41	-26	0 SBG
6/5/2022	3	PQ.OUTAOUAIS.SINK.	PQAT	-99	-99	15	-136	0 SBG
6/5/2022	4	PQ.OUTAOUAIS.SINK.	PQAT	-99	-99	15.26	-145	0 SBG
6/5/2022	7	PQ.OUTAOUAIS.SINK.	PQAT	-59	-59	15	-59	0 SBG
6/6/2022	6	PQ.OUTAOUAIS.SINK.	PQAT	-57	-57	6.68	-57	0 SBG
6/10/2022	7	NY.ROSETON.SINK.0:	NYSI	-100	-65	30.27	-95	0 SBG
6/11/2022	7	PQ.OUTAOUAIS.SINK.	PQAT	-47	-47	15.42	-135	0 SBG
6/12/2022	3	MN.INTFALLS.US.SINI	MNSI	-5	-5	48	-5	0 SBG
6/13/2022	3	PQ.OUTAOUAIS.SINK.	PQAT	-59	-59	25	-59	0 SBG
6/13/2022	6	PQ.OUTAOUAIS.SINK.	PQAT	-59	-5	11.63	-5	0 SBG
5/16/2018	9	NY.ROSETON.SINK.02	NYSI	-15	-15	2.3	-15	0 SBG (?)
5/16/2018	16	NY.ROSETON.SINK.01	NYSI	-50	-5	8.97	-5	0 SBG (?)
5/18/2018	11	NY.ROSETON.SINK.01	NYSI	-50	-20	23.2	-20	0 SBG (?)
5/18/2018	12	NY.ROSETON.SINK.01	NYSI	-50	-20	20.55	-20	0 SBG (?)
5/18/2018	12	MI.LUDINGTON.SINK.(	MISI	-11	-11	25.47	-36	0 SBG (?)
5/18/2018	13	NY.ROSETON.SINK.01	NYSI	-14	-4	19.88	-4	0 SBG (?)
5/18/2018	14	NY.ROSETON.SINK.01	NYSI	-50	-25	20.48	-25	0 SBG (?)
5/18/2018	15	NY.ROSETON.SINK.01	NYSI	-50	-25	22.2	-25	0 SBG (?)
5/18/2018	16	NY.ROSETON.SINK.01	NYSI	-50	-25	16.88	-25	0 SBG (?)
5/18/2018	17	NY.ROSETON.SINK.01	NYSI	-50	-15	14.88	-65	0 SBG (?)
5/18/2018	17	NY.ROSETON.SINK.02	NYSI	-50	-50	14.88	-65	0 SBG (?)
5/22/2018	10	MI.LUDINGTON.SINK.(	MISI	-25	-25	16.48	-25	0 SBG (?)
5/22/2018	12	NY.ROSETON.SINK.02	NYSI	-50	-25	2.88	-50	0 SBG (?)
9/12/2018	4	MI.LUDINGTON.SINK.(	MISI	-50	-50	6.91	-100	0 SBG (?)
9/12/2018	4	MI.LUDINGTON.SINK.(	MISI	-50	-50	6.91	-100	0 SBG (?)
########	1	NY.ROSETON.SINK.01	NYSI	-250	-250	30.34	-250	0 SBG (?)
########	9	NY.ROSETON.SINK.1(	NYSI	-25	-25	21.2	-25	0 SBG (?)
########	5	MB.WHITESHELL.US.!	MBSI	-50	-50	56.8	-50	0 SBG (?)
########	20	MB.WHITESHELL.US.!	MBSI	-50	-50	9.32	-50	0 SBG (?)
5/30/2019	8	MB.WHITESHELL.US.!	MBSI	-50	-38	12.08	-122	0 SBG (?)
10/8/2019	11	NY.ROSETON.SINK.2!	NYSI	-10	-10	13.8	-10	0 SBG (?)
10/8/2019	11	MI.LUDINGTON.SINK.(	MISI	-50	-50	19.09	-50	0 SBG (?)
3/29/2020	9	NY.ROSETON.SINK.0:	NYSI	-163	-163	0.01	-179	0 SBG (?)
3/29/2020	21	MB.WHITESHELL.US.!	MBSI	-50	-50	3.56	-50	0 SBG (?)
3/29/2020	21	NY.ROSETON.SINK.01	NYSI	-200	-100	7.26	-200	0 SBG (?)
4/6/2021	13	MN.INTFALLS.US.SOL	MNSI	100	100	7.1	-30	100 SBG (?)

Date	Hour	Resource Name	Scheduling Point	Nexus Sch	Nexus Fail ICP	Total Failed Exports	Total Failed Imports	SGB condition

CSV data shared with Nexus via Workspaces April 12, 2024

Note: There are 1658 transactions listed in the notice appendix. Three transactions were removed from the appendix as they were adjusted via the Settlement NOD process.

The preliminary accrued benefit noted in the table following paragraph 8 in the notice accounts for the three removed transactions.

The ICP column is the intertie price less the Ontario price.

The Total Failed Exports/Imports columns indicate the total failed MWs for the date and hour indicated in columns A and B, at the intertie listed in column D.

########	1	MI.LUDINGTON.SINK.(	MISI	-1	-1	37.52	-1	0
########	15	NY.ROSETON.SINK.01	NYSI	-100	-100	25	-150	0
########	16	NY.ROSETON.SINK.01	NYSI	-100	-100	18.76	-100	0
########	2	NY.ROSETON.SINK.01	NYSI	-41	-21	57.99	-21	0
########	4	NY.ROSETON.SINK.01	NYSI	-60	-60	35.02	-60	0
########	13	NY.ROSETON.SINK.01	NYSI	-10	-10	2.72	-10	0
1/2/2018	15	NY.ROSETON.SINK.02	NYSI	-14	-4	33.43	-4	0
1/2/2018	19	NY.ROSETON.SINK.01	NYSI	-110	-35	119.73	-35	0
1/4/2018	10	NY.ROSETON.SINK.02	NYSI	-10	-10	81.52	-10	0
1/8/2018	10	NY.ROSETON.SINK.01	NYSI	-5	-5	92.41	-5	0
1/8/2018	18	NY.ROSETON.SINK.01	NYSI	-20	-10	27.36	-10	0
1/9/2018	19	NY.ROSETON.SINK.01	NYSI	-40	-5	8.29	-5	0
1/10/2018	10	NY.ROSETON.SINK.01	NYSI	-60	-15	15.91	-15	0
1/11/2018	1	NY.ROSETON.SINK.01	NYSI	-20	-10	23.12	-10	0
1/11/2018	15	NY.ROSETON.SINK.01	NYSI	-20	-5	22.22	-5	0
1/14/2018	20	NY.ROSETON.SINK.01	NYSI	-50	-50	72.59	-50	0
1/15/2018	11	NY.ROSETON.SINK.02	NYSI	-10	-10	56.39	-110	0
1/23/2018	13	NY.ROSETON.SINK.01	NYSI	-10	-10	16.83	-10	0
1/26/2018	23	NY.ROSETON.SINK.01	NYSI	-100	-50	26	-50	0
1/31/2018	15	NY.ROSETON.SINK.02	NYSI	-20	-10	27.13	-10	0
2/15/2018	15	MI.LUDINGTON.SINK.(	MISI	-25	-25	6.99	-25	0
2/17/2018	14	MI.LUDINGTON.SINK.(	MISI	-11	-11	11.13	-11	0
2/19/2018	15	NY.ROSETON.SINK.01	NYSI	-150	-25	4.48	-25	0

Exhibit "D"

Nexus Energy's Notice of Dispute dated December 23, 2024

Exhibit "D"

to the Affidavit of Francois Tardif

Sworn before me on October 29, 2025, in accordance with O. Reg. 431/20,
Administering Oath or Declaration Remotely



Commissioner for Taking Affidavits
(or as may be)

October 29, 2025

Keith Edward Hickey, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.

Expires June 24, 2027.

Docusign Envelope ID: 897EEBF0-FF57-401F-8F8F-227B02187D49

Dispute Resolution

Notice of Dispute

To commence good faith negotiations complete Parts 1, 2, 3 and 5 of this form. Serve the Notice of Dispute on the respondent(s) by prepaid first class mail, fax, electronic mail, courier or other form of personal delivery. Ensure you retain your proof of service. Service by email will be effective when email confirmation has been received by the party serving the Notice of Dispute from the receiving party. If the IESO is a respondent, send the Notice of Dispute to the address below to the attention of General Counsel. In all cases, send a copy to Dispute Resolution, Legal Services at the IESO at:

120 Adelaide Street West, Suite 1600

Toronto, ON

M5H 1T1

Fax number: 416-506-2843

Email: IESO-LegalServices@ieso.ca

In the event that the dispute is not resolved through good faith negotiations, to commence the arbitration or mediation processes, complete all sections of this form

1. Submit this form and all attachments by prepaid first class mail, facsimile, electronic mail, courier or other form of personal delivery to the respondent(s). Retain proof of service.
2. File the Notice of Dispute form, proof(s) of service on the respondent(s), and all attachments with the Secretary Dispute Panel by prepaid first class mail, facsimile, electronic mail, courier or other form of personal delivery at following addresses:

   The Secretary, Dispute Resolution Panel

   120 Adelaide Street West, Suite 1600

   Toronto, ON

   M5H 1T1

   Fax number: 416-506-2843

   Email: IESO-LegalServices@ieso.ca

Docusign Envelope ID: 897EEBF0-FF57-401F-8F8F-227B02187D49

All information submitted in this process will be used by the IESO solely in support of its obligations under the "Electricity Act, 1998", the "Ontario Energy Board Act, 1998", the "Market Rules" and associated policies, standards and procedures and its licence. All information submitted will be assigned the appropriate confidentiality level upon receipt.

Terms and acronyms used in this Form that are italicized have the meanings ascribed thereto in Chapter 11 of the "Market Rules"

Name and Address of *Respondent:*

Party Name:	Independent Electricity System Operator
Street Address:	120 Adelaide Street West, Suite 1600
City, Province:	Toronto, Ontario
Postal Code:	M5H 1T1
Telephone Number:	
Fax Number:	

-and-

Name and Address of Other *Respondent* (if any):
Party Name:
Street Address:
City, Province:
Postal Code:
Fax Number:

Part 1 – General Information about the *Applicant*

Organization Name: Nexus Energy Inc.	
Address: 4789 Yonge Street, Suite 916	
City/Town: Toronto	Province/State: ON
Postal/Zip Code: M2N 0G3	Country: Canada
Main Contact	
Name: Ali Qaisar	Title: General Counsel
Telephone No.: 437-238-6128	E-mail Address: ali.qaisar@nexusenergy.com
Market Participant/Metering Service Provider No.: 186267	IESO Customer Relations Ticket No. (if available):

Docusign Envelope ID: 897EEBF0-FF57-401F-8F8F-227B02187D49

Dispute Number:	(to be assigned by IESO upon receipt)

Alternate Contact (if any)

Name: Francois Tardif

Title: Director, Risk & Regulatory Affairs

Telephone No.: 416-551-7125

E-mail Address: francois.tardif@nexusenergy.com

Fax Number: 416.901.8157

Part 2 – Information about the Dispute

Is there a section of the Market Rules involved in the dispute?

☒Yes ☐ No

Please cite the Market Rules section number(s):

Chapter 7, section 7.5.8A and 7.5.8B
Chapter 3, sections 6.6.10A and 6.2.7.4

Please cite the basis for the dispute:

Chapter 3, section 2.2.1.1

If a settlement statement re-calculation is requested, please indicate the contested amount.

$2,078,824.92

Docusign Envelope ID: 897EEBF0-FF57-401F-8F8F-227B02187D49

Part 3 – Detailed Description of *Dispute*

This description **must** include:

- The nature and the basis for the complaint;
- The *Market Rules* at issue;
- The parties to the dispute and the name of any person having knowledge of, or who may be directly affected by, the dispute;
- A concise summary of the facts underlying the dispute;
- The relief sought and a summary of the grounds for such relief; and
- A description of any documentation on which the *applicant* intends to rely in support of its claim. Copies of the documentation may, but need not, be provided as part of the *Notice of Dispute*.

("Market Rules", Chapter 3, Section 2.5)

Part 3 – Detailed Description of *Dispute (continued)*

On December 17, 2024, MACD issued a notice of non-compliance with sanction assessment and order (together, the "IESO Order"). The IESO Order requires the adjustment of settlement amounts relating to Nexus Energy to, inter alia, recover "congestion rents" in allegedly avoided by Nexus Energy in relation to the subject transactions.

Nexus Energy disputes that "avoided congestion rents" constitute "settlement amounts" that may be recovered under Chapter 3, section 6.6.10A of the Market Rules or at all. Alternatively, even if "avoided congestion rents" may be recovered by the IESO, Nexus Energy disputes that the circumstances surrounding the subject transactions warrant action under Section 6.6.10A. Further, it is Nexus Energy's position that the manner in which MACD has approached the issue of failed intertie transactions in general, and in Nexus Energy's case in particular, is contrary to its mandate to foster compliance in the wholesale electricity market in Ontario and is discriminatory and unfairly prejudicial to Nexus Energy.

Nexus Energy requests the IESO Order be set aside to the extent that it requires the adjustment of settlement amounts on account of "avoided congestion rents".

Persons who may knowledge of the dispute include, but are not limited to:

1. Ali Qaisar - General Counsel, Nexus Energy
2. Francois Tardif - Director, Risk & Regulatory Affairs, Nexus Energy
3. Robin Doolittle - Managing Director, Trading & Marketing, Nexus Energy
4. William Mercer - Head of Physical Trading, Nexus Energy
5. Bob Yeoman - Sr. Manager, Rule Enforcement, MACD
6. Egor Sitnik - Supervisor, Compliance Investigations, MACD
7. John Koetsier - Senior Analyst, MACD

Docusign Envelope ID: 897EEBF0-FF57-401F-8F8F-227B02187D49

Documentation that Nexus Energy intends to rely on includes, but is not limited to:

1. IESO Notice of Alleged Breach dated April 4, 2024

2. Nexus Energy's written response dated July 9, 2024 to the Notice of Alleged Breach, and all historical IESO materials referenced therein

3. IESO Notice of Non-Compliance dated December 17, 2024, including IESO order

6. Monitoring Reports issued by the Market Surveillance Panel of the Ontario Energy Board from 2010 through to the present day.

Part 4 – Summary of *Dispute*

Please summarize the information provided in Part 3. This section must be completed if the good faith negotiations fail to resolve the dispute between the parties. This summary will be posted on the publically available *IESO* Web site in the event that the dispute proceeds to arbitration. ("Market Rules", Chapter 3, Section 2.5)

Docusign Envelope ID: 897EEBF0-FF57-401F-8F8F-227B02187D49

To be provided if the good faith negotiations fail to resolve the dispute between the parties.

Part 5 – Declaration

The undersigned, a duly authorized representative of the *applicant*, hereby declares that the information contained in and submitted in support of this *Notice of Dispute* is, to the best of the *applicant's* knowledge, complete and accurate.

Dated at the City of Toronto , in the Province/State of Ontario, this 23 day of December, 2024.

Signature: DocuSigned by: Ali Qaisar 57BD875DF61948E...

Name: Ali Qaisar

Title: General Counsel, Nexus Energy Inc.

I have authority to bind the *applicant.*

Please attach a copy of any documents that you wish to provide in support of the claims made in this *Notice of Dispute*.

Attachments Included:

☐ Yes ☒ No

Total Number of Pages (including this *Notice of Dispute* and all attachments): 7

Exhibit "E"

MACD's email to Secretary of IESO Dispute Resolution Panel dated April 1, 2025

Exhibit "E"

to the Affidavit of Francois Tardif

Sworn before me on October 29, 2025, in accordance with O. Reg. 431/20,
Administering Oath or Declaration Remotely



_____

Commissioner for Taking Affidavits
(or as may be)

October 29, 2025

Keith Edward Hickey, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.

Expires June 24, 2027.

Archived: Thursday, October 9, 2025 7:39:14 PM
From: Wilson, Michael
Mail received time: Tue, 1 Apr 2025 11:19:59
Sent: Tue, 1 Apr 2025 11:19:50
To: ieso-legalservices@ieso.ca
Cc: Goyal, Reena Lisa Barnet Bob Yeoman
Subject: RE: Nexus Energy - Amended Notice of Dispute
Importance: Normal
Sensitivity: None

• External Email | Courrier électronique externe •

Dear Secretary,

Notice of Dispute and Response to same has been submitted in accordance with the timelines set out in the Market Rules, and the parties previously advised that they have agreed to the appointment of Mr. Newbould as mediator.

If there is anything the parties need to do to advance Mr. Newbould's appointment as mediator (e.g., if we need to reach out to him directly), please advise.

To be clear, we disagree with the characterization of compliance with the timelines as set out in Nexus' Amended Notice of Dispute; MACD stands ready to advance through the dispute resolution process as Nexus Energy chooses to advance it.

Thank you,

Michael

Michael Wilson
Goodmans LLP

416.597.4130
mwilson@goodmans.ca

From: Goyal, Reena <reena.goyal@blakes.com>
Sent: Monday, March 31, 2025 1:01 PM
To: ieso-legalservices@ieso.ca
Cc: Wilson, Michael <mwilson@goodmans.ca>
Subject: Nexus Energy - Amended Notice of Dispute

Dear Secretary –

Attached please find the amended notice of dispute of the applicant Nexus Energy Inc., hereby filed pursuant to Chapter 3 of the IESO market rules. Proof of service on the respondent IESO is attached.

Thank you,

Reena Goyal J.D., L.L.M. (she, her, hers)
Counsel
reena.goyal@blakes.com
T. +1-416-863-5807
C. +1-416-931-2857

Blake, Cassels & Graydon LLP
199 Bay Street, Suite 4000, Toronto ON M5L 1A9 (Map)
blakes.com | LinkedIn



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***** Attention *****

This communication is intended solely for the named addressee(s) and may contain information that is privileged, confidential, protected or otherwise exempt from disclosure. No waiver of confidence, privilege, protection or otherwise is made. If you are not the intended recipient of this communication, or wish to unsubscribe, please advise us immediately at privacyofficer@goodmans.ca and delete this email without reading, copying or forwarding it to anyone. Goodmans LLP, 333 Bay Street, Suite 3400, Toronto, ON, M5H 2S7, www.goodmans.ca. You may unsubscribe to certain communications by clicking here.

Exhibit "F"

Nexus Energy's Amended Notice of Dispute dated March 31, 2025

Exhibit "F"

to the Affidavit of Francois Tardif

Sworn before me on October 29, 2025, in accordance with O. Reg. 431/20, Administering Oath or Declaration Remotely



Commissioner for Taking Affidavits
(or as may be)

October 29, 2025

Keith Edward Hickey, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.

Expires June 24, 2027.

Dispute Resolution

Notice of Dispute

To commence good faith negotiations complete Parts 1, 2, 3 and 5 of this form. Serve the Notice of Dispute on the respondent(s) by prepaid first class mail, fax, electronic mail, courier or other form of personal delivery. Ensure you retain your proof of service. Service by email will be effective when email confirmation has been received by the party serving the Notice of Dispute from the receiving party. If the IESO is a respondent, send the Notice of Dispute to the address below to the attention of General Counsel. In all cases, send a copy to Dispute Resolution, Legal Services at the IESO at:

120 Adelaide Street West, Suite 1600

Toronto, ON

M5H 1T1

Fax number: 416-506-2843

Email: IESO-LegalServices@ieso.ca

In the event that the dispute is not resolved through good faith negotiations, to commence the arbitration or mediation processes, complete all sections of this form

1. Submit this form and all attachments by prepaid first class mail, facsimile, electronic mail, courier or other form of personal delivery to the respondent(s). Retain proof of service.
2. File the Notice of Dispute form, proof(s) of service on the respondent(s), and all attachments with the Secretary Dispute Panel by prepaid first class mail, facsimile, electronic mail, courier or other form of personal delivery at following addresses:

   The Secretary, Dispute Resolution Panel

   120 Adelaide Street West, Suite 1600

   Toronto, ON

   M5H 1T1

   Fax number: 416-506-2843

   Email: IESO-LegalServices@ieso.ca

All information submitted in this process will be used by the IESO solely in support of its obligations under the "Electricity Act, 1998", the "Ontario Energy Board Act, 1998", the "Market Rules" and associated policies, standards and procedures and its licence. All information submitted will be assigned the appropriate confidentiality level upon receipt.

Terms and acronyms used in this Form that are italicized have the meanings ascribed thereto in Chapter 11 of the "Market Rules"

Name and Address of *Respondent:*

Party Name:	Independent Electricity System Operator - MACD
Street Address:	120 Adelaide Street West, Suite 1600
City, Province:	Toronto, ON
Postal Code:	M5H 1T1
Telephone Number:	
Fax Number:	

-and-

Name and Address of Other *Respondent* (if any):
Party Name:
Street Address:
City, Province:
Postal Code:
Fax Number:

Part 1 – General Information about the *Applicant*

Organization Name: Nexus Energy Inc.	
Address: 4789 Yonge Street, Suite 916	
City/Town: Toronto	Province/State: ON
Postal/Zip Code: M2N 0G3	Country: Canada
Main Contact	
Name: Ali Qaisar	Title: General Counsel
Telephone No.: 437-238-6128	E-mail Address: ali.qaisar@nexusenergy.com
Market Participant/Metering Service Provider No.: 186267	IESO Customer Relations Ticket No. (if available):

Dispute Number:	(to be assigned by IESO upon receipt)

Alternate Contact (if any)

Name: Reena Goyal | Title: Counsel

Telephone No.: 4168635807 | E-mail Address: reena.goyal@blakes.com

Fax Number:

Part 2 – Information about the Dispute

Is there a section of the Market Rules involved in the dispute?

☒Yes ☐ No

Please cite the Market Rules section number(s):

Chapter 3, sections 2.2.1.1, 2.6.2, 6.6.10A and 6.2.7.4

Chapter 7, sections 7.5.8A and 7.5.8B

Please cite the basis for the dispute:

See Parts 3 and 4.

If a settlement statement re-calculation is requested, please indicate the contested amount.

$2,078,824.92

Part 3 – Detailed Description of *Dispute*

This description **must** include:

- The nature and the basis for the complaint;
- The *Market Rules* at issue;
- The parties to the dispute and the name of any person having knowledge of, or who may be directly affected by, the dispute;
- A concise summary of the facts underlying the dispute;
- The relief sought and a summary of the grounds for such relief; and
- A description of any documentation on which the *applicant* intends to rely in support of its claim. Copies of the documentation may, but need not, be provided as part of the *Notice of Dispute*.

("Market Rules", Chapter 3, Section 2.5)

Part 3 – Detailed Description of *Dispute (continued)*

On December 17, 2024, MACD issued a notice of non-compliance with sanction assessment and order (together, the "IESO Order"). The IESO Order requires the adjustment of settlement amounts relating to Nexus Energy to, inter alia, recover "congestion rents" in allegedly avoided by Nexus Energy in relation to the subject transactions.

Nexus Energy disputes that "avoided congestion rents" constitute "settlement amounts" that may be recovered under Chapter 3, section 6.6.10A of the Market Rules or at all.

Alternatively, even if "avoided congestion rents" may be recovered by the IESO, Nexus Energy disputes that the circumstances surrounding the subject transactions warrant action under Section 6.6.10A. Further, it is Nexus Energy's position that the manner in which MACD has approached the issue of failed intertie transactions in general, and in Nexus Energy's case in particular, is contrary to its mandate to foster compliance in the wholesale electricity market in Ontario and is discriminatory and unfairly prejudicial to Nexus Energy.

Nexus Energy requests the IESO Order be set aside to the extent that it requires the adjustment of settlement amounts on account of "avoided congestion rents".

Persons who may knowledge of the dispute include, but are not limited to:

1. Ali Qaisar - General Counsel, Nexus Energy
2. Francois Tardif - Director, Risk & Regulatory Affairs, Nexus Energy
3. Robin Doolittle - Managing Director, Trading & Marketing, Nexus Energy

4. William Mercer - Head of Physical Trading, Nexus Energy

5. Bob Yeoman - Sr. Manager, Rule Enforcement, MACD

6. Egor Sitnik - Supervisor, Compliance Investigations, MACD

7. John Koetsier - Senior Analyst, MACD

Documentation that Nexus Energy intends to rely on includes, but is not limited to:

1. IESO Notice of Alleged Breach dated April 4, 2024

2. Nexus Energy's written response dated July 9, 2024 to the Notice of Alleged Breach, and all historical IESO materials referenced therein

3. IESO Notice of Non-Compliance dated December 17, 2024, including IESO order

6. Monitoring Reports issued by the Market Surveillance Panel of the Ontario Energy Board from 2010 through to the present day.

Part 4 – Summary of *Dispute*

Please summarize the information provided in Part 3. This section must be completed if the good faith negotiations fail to resolve the dispute between the parties. This summary will be posted on the publically available *IESO* Web site in the event that the dispute proceeds to arbitration. ("Market Rules", Chapter 3, Section 2.5)

On December 17, 2024, the Markets Assessment and Compliance Division ("MACD") of the Independent Electricity System Operator ("IESO") issued a notice of non-compliance alleging that Nexus Energy Inc. ("Nexus") had breached the IESO's market rules with respect to certain failed scheduled intertie transactions over a period spanning from December 2017 up to and including December 2023 ("IESO Order"). The subject transactions constituted a small percentage of transactions scheduled by Nexus during the relevant period and Nexus did not receive any significant transmission rights benefits or other revenues as a result of the failed transactions. The IESO has not assessed any penalties or sanctions against Nexus with respect to said failed intertie transactions and is instead seeking to affect a settlement adjustment to recover "congestion rents" allegedly avoided by Nexus when those intertie transactions failed, as those congestion rents are not included in the calculation of the failure charge assessed to market participants in the Ontario wholesale electricity market.

Nexus Energy disputes the authority of the IESO to recover "avoided congestion rents" under the market rules with respect to the subject failed transactions. Alternatively, even if "avoided congestion rents" may be recovered by the IESO, Nexus Energy disputes that the circumstances surrounding the subject transactions warrant such action based on a purposive interpretation of the relevant market rules.

Furthermore, following Nexus' filing a notice of dispute with the IESO on February 11th, 2025 challenging the lawfulness of the IESO Order, the IESO has failed to appoint a mediator or even acknowledge receipt of the notice of dispute within the timelines prescribed by the Market Rules.

Part 5 – Declaration

The undersigned, a duly authorized representative of the *applicant*, hereby declares that the information contained in and submitted in support of this *Notice of Dispute* is, to the best of the *applicant's* knowledge, complete and accurate.

Dated at the City of Toronto , in the Province/State of Ontario, this 31 day of March, 2025.

Signature: 

Name: Ali Qaisar (per Reena Goyal)

Title: General Counsel

I have authority to bind the *applicant.*

Please attach a copy of any documents that you wish to provide in support of the claims made in this *Notice of Dispute*.

Attachments Included:

☐ Yes ☒ No

Total Number of Pages (including this *Notice of Dispute* and all attachments): 7

Exhibit “G”

IESO corporate organization charts

Exhibit “G”

to the Affidavit of Francois Tardif

Sworn before me on October 29, 2025, in accordance with O. Reg. 431/20,
Administering Oath or Declaration Remotely



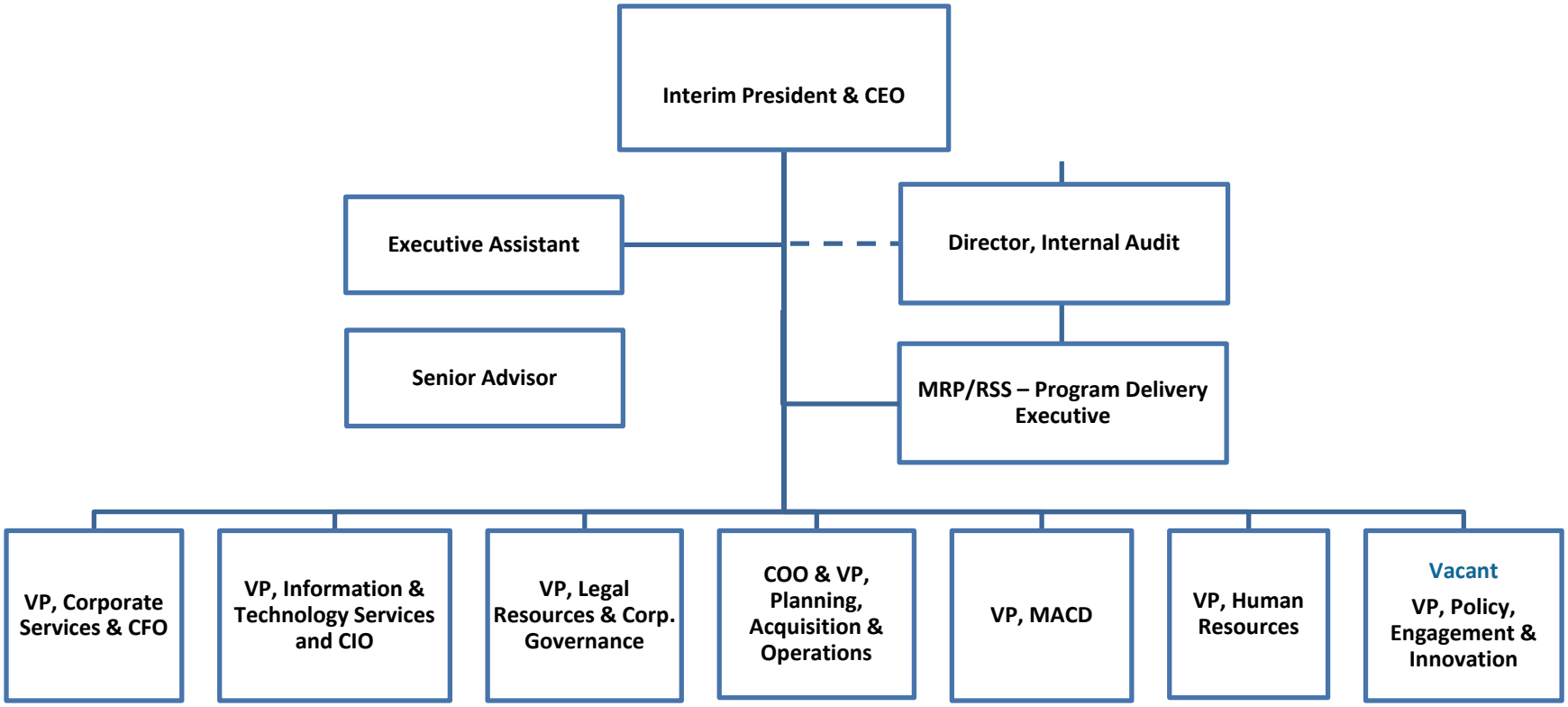
Commissioner for Taking Affidavits
(or as may be)

October 29, 2025

Keith Edward Hickey, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.

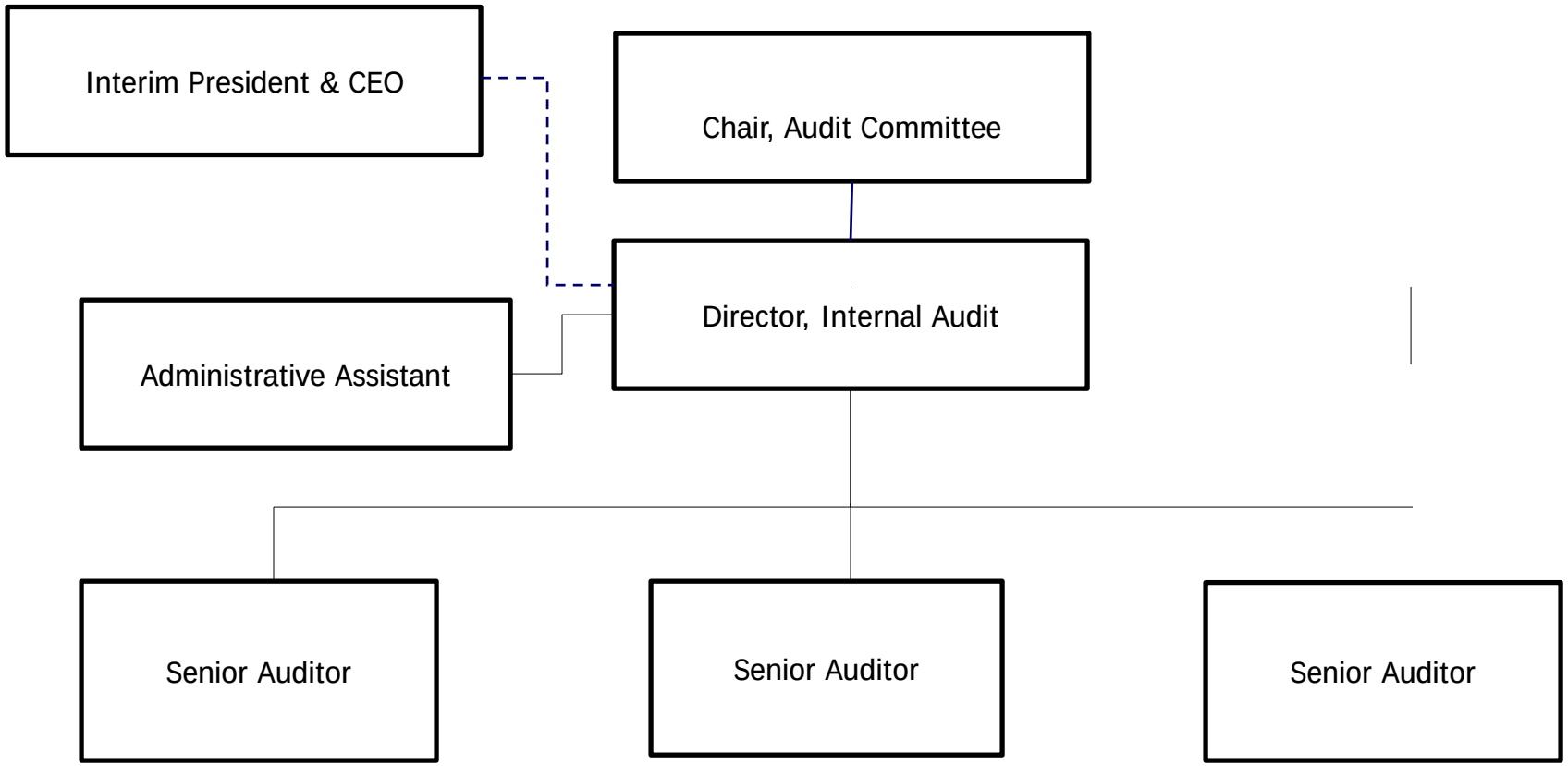
Expires June 24, 2027.

IESO

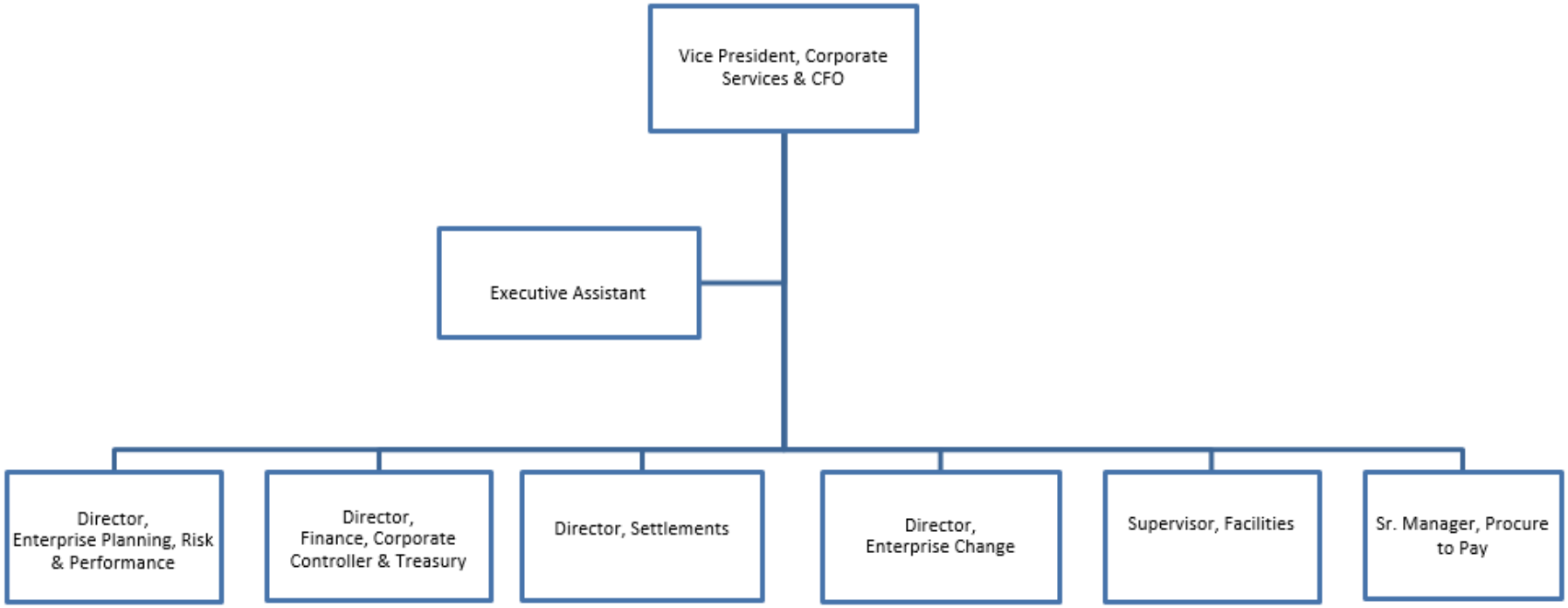


Effective Date: January 25, 2021

Internal Audit Organization



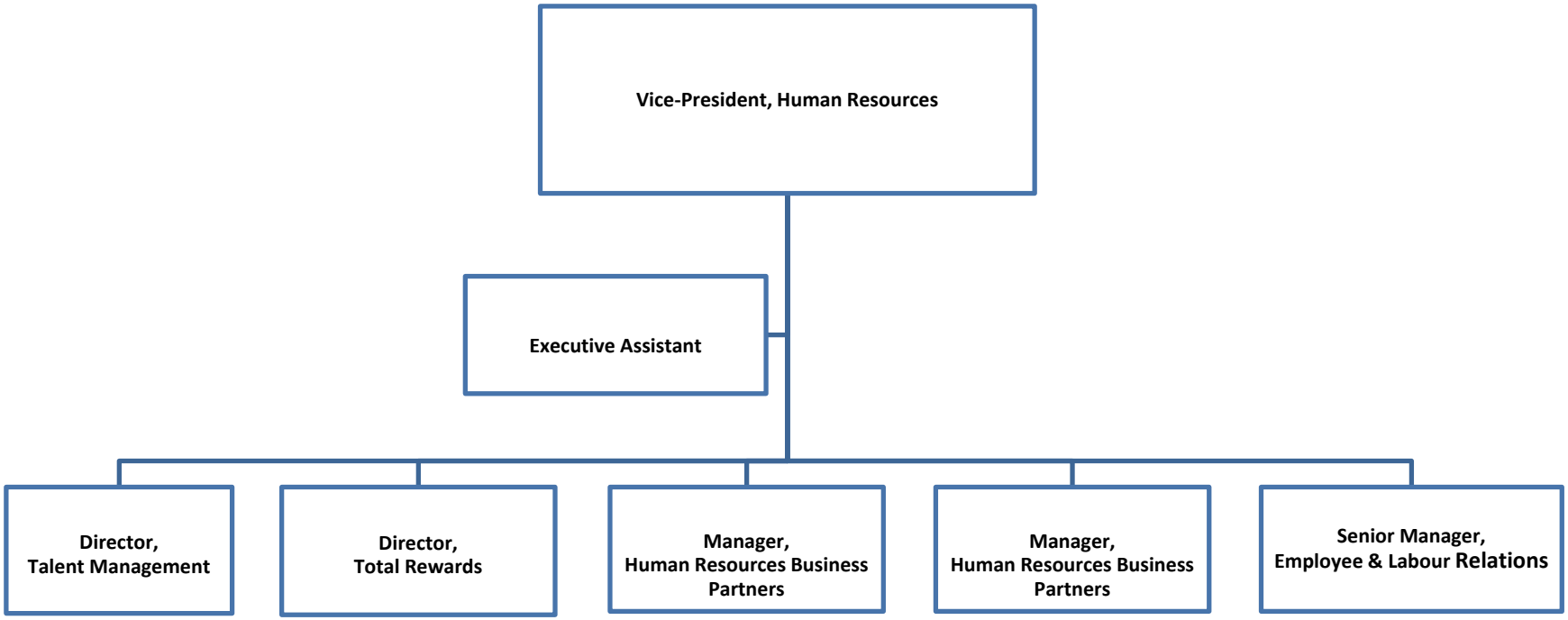
CORPORATE SERVICES



Effective Date: May 20, 2021

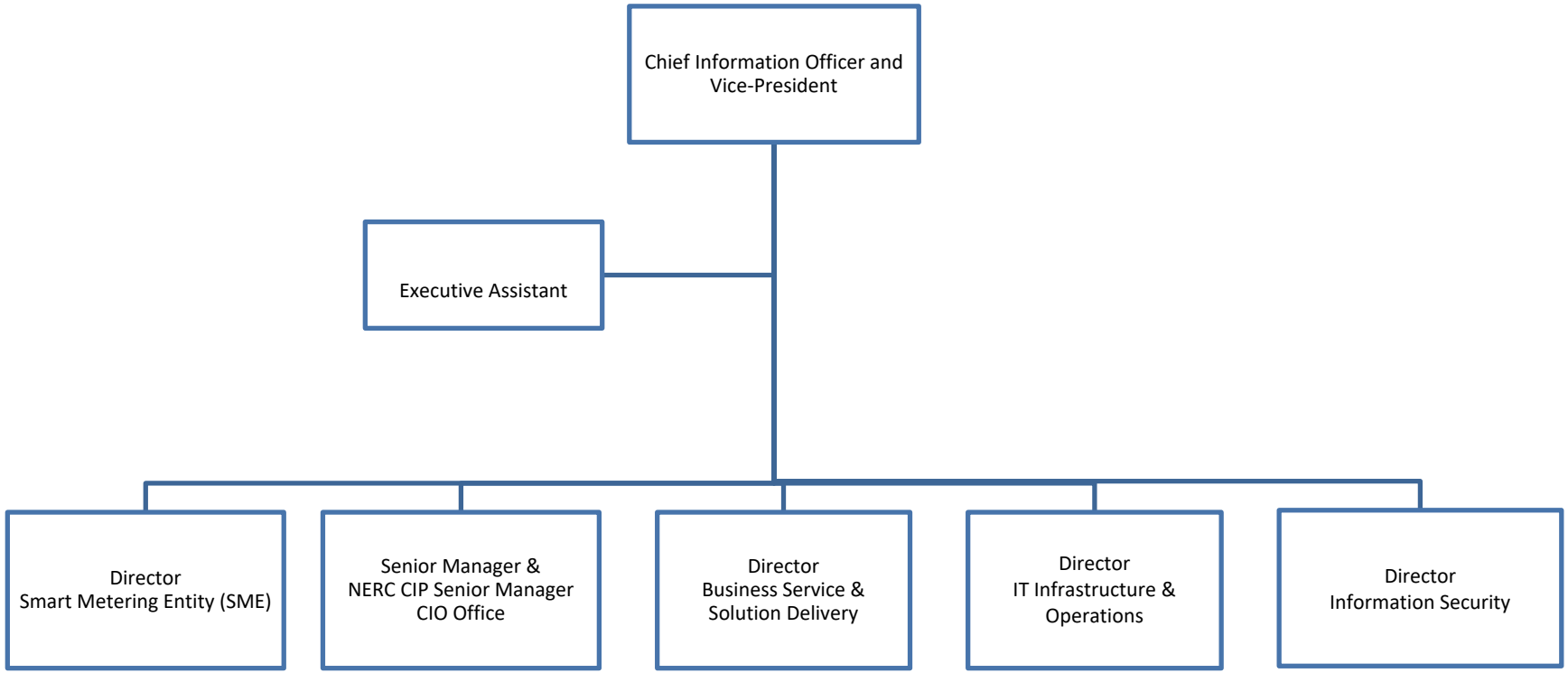
A1698

HUMAN RESOURCES



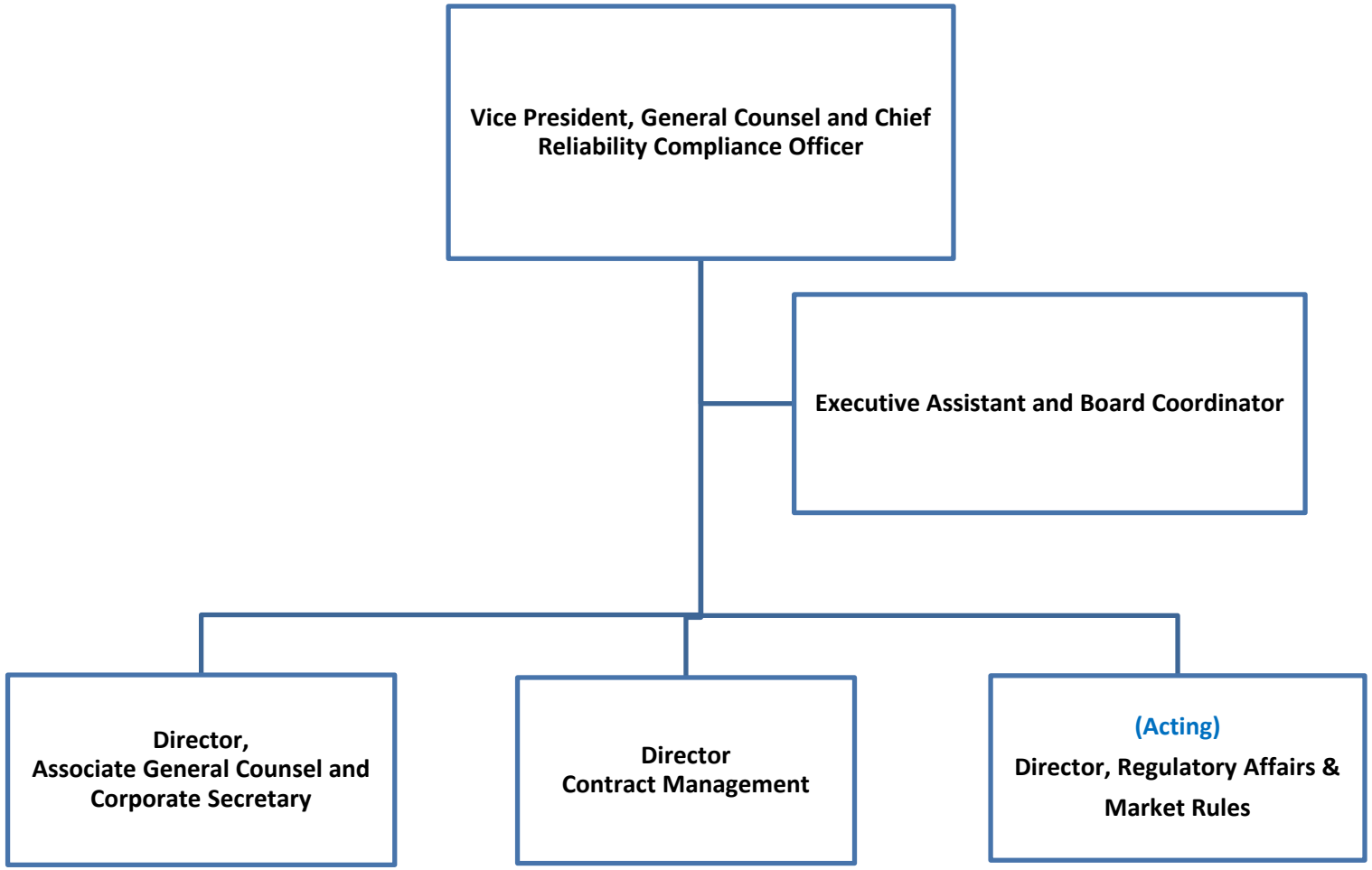
Effective Date: May 3, 2021

INFORMATION & TECHNOLOGY SERVICES



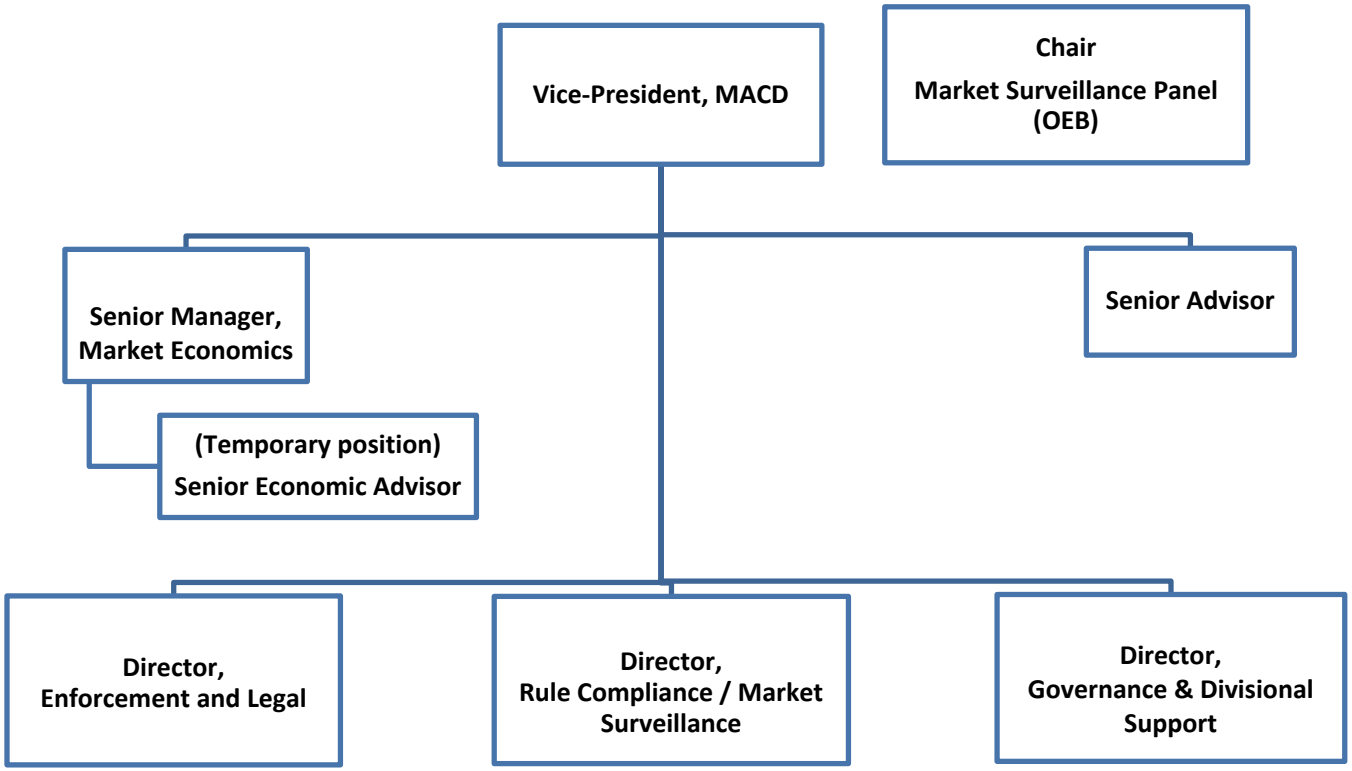
Effective Date: May 3, 2021

LEGAL RESOURCES AND CORPORATE GOVERNANCE



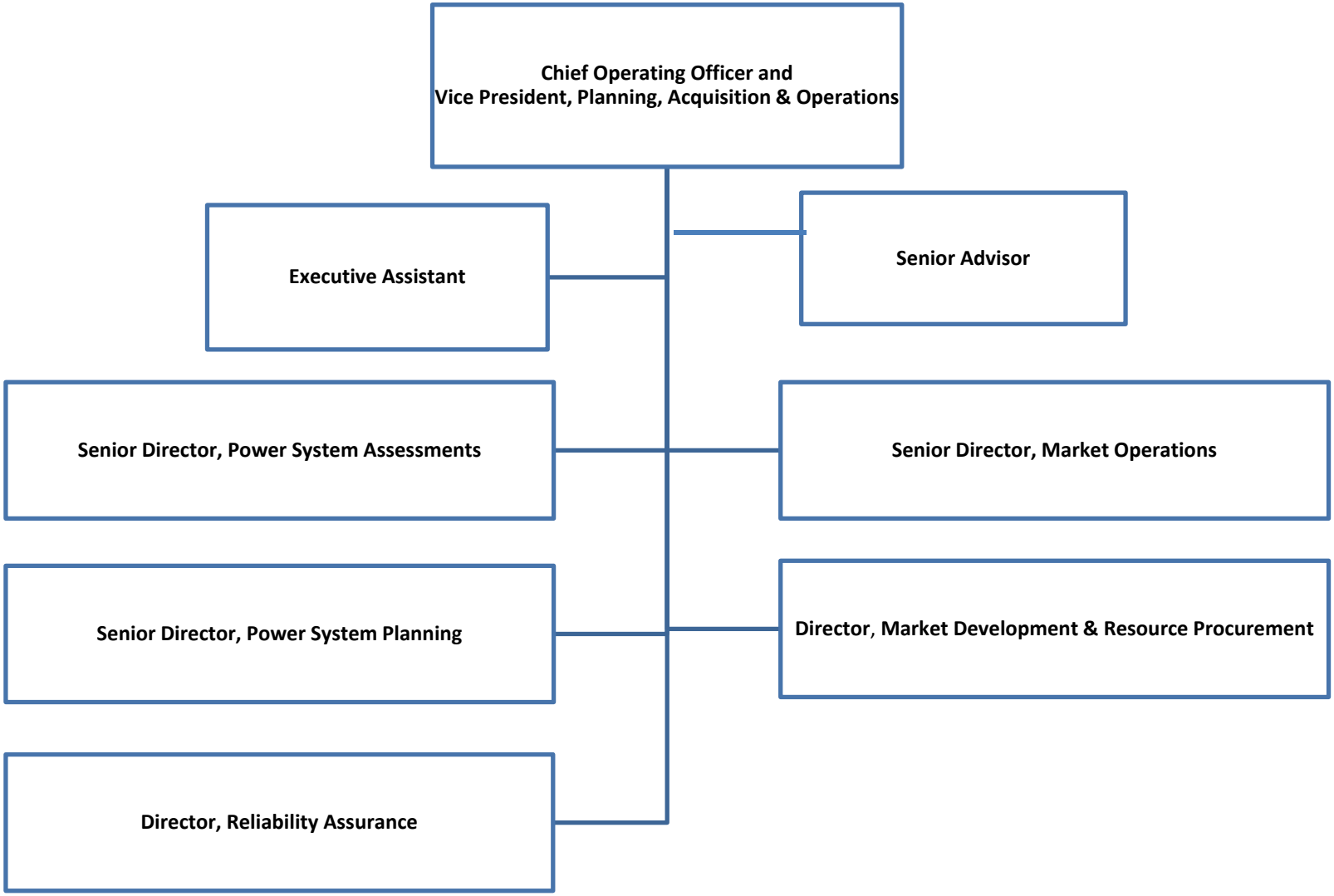
Effective Date: March 4, 2021

MARKET ASSESSMENT AND COMPLIANCE DIVISION



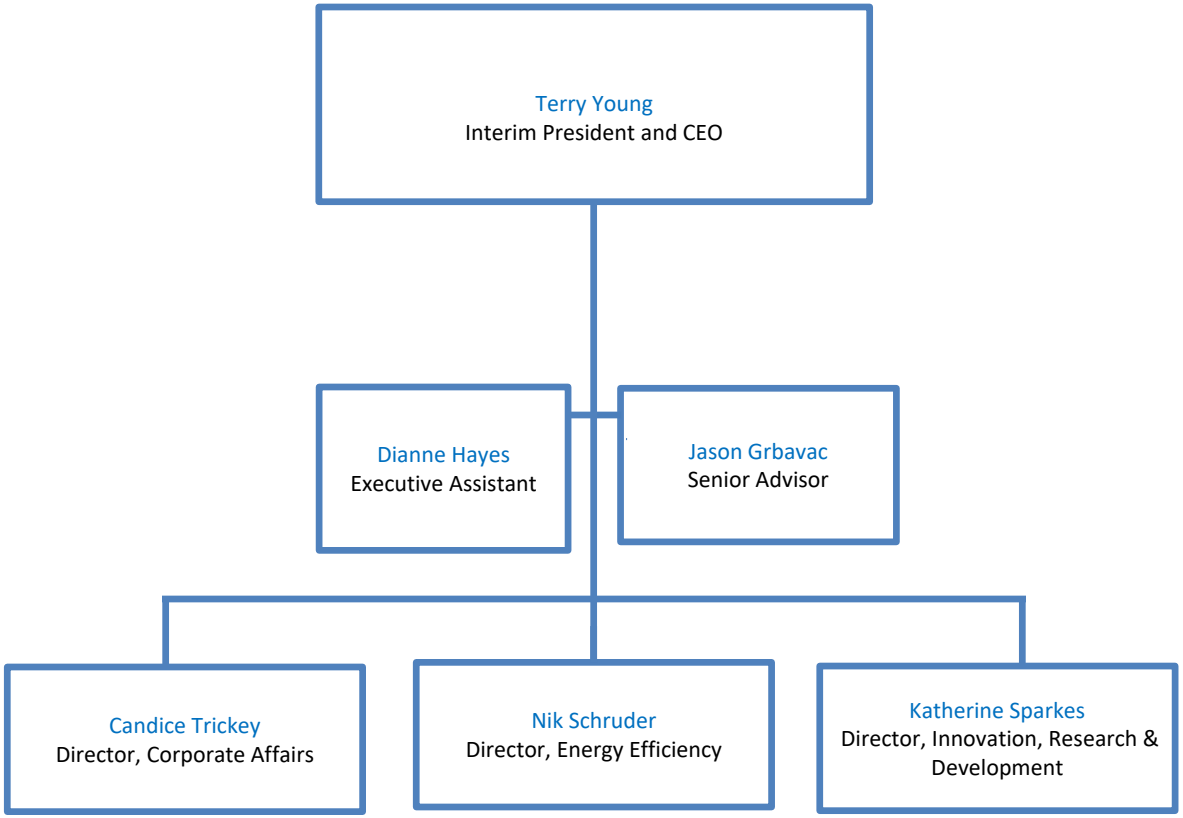
Effective Date: April 1, 2021

PLANNING, ACQUISITION AND OPERATIONS



Effective Date: May 3, 2021

POLICY, ENGAGEMENT & INNOVATION



Effective Date: May 10, 2021

Exhibit “H”

Nexus Energy’s further Amended Notice of Dispute dated May 21, 2025

Exhibit “H”

to the Affidavit of Francois Tardif

Sworn before me on October 29, 2025, in accordance with O. Reg. 431/20,
Administering Oath or Declaration Remotely



Commissioner for Taking Affidavits
(or as may be)

October 29, 2025

Keith Edward Hickey, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.

Expires June 24, 2027.

Notice of Dispute

To commence good faith negotiations complete Parts 1, 2, 3 and 5 of this form. Serve the Notice of Dispute on the respondent(s) by prepaid first class mail, fax, electronic mail, courier or other form of personal delivery. Ensure you retain your proof of service. Service by email will be effective when email confirmation has been received by the party serving the Notice of Dispute from the receiving party. If the IESO is a respondent, send the Notice of Dispute to the address below to the attention of General Counsel. In all cases, send a copy to Dispute Resolution, Legal Services at the IESO at:

120 Adelaide Street West, Suite 1600

Toronto, ON

M5H 1T1

Fax number: 416-506-2843

Email: IESO-LegalServices@ieso.ca

In the event that the dispute is not resolved through good faith negotiations, to commence the arbitration or mediation processes, complete all sections of this form

1. Submit this form and all attachments by prepaid first class mail, facsimile, electronic mail, courier or other form of personal delivery to the respondent(s). Retain proof of service.
2. File the Notice of Dispute form, proof(s) of service on the respondent(s), and all attachments with the Secretary Dispute Panel by prepaid first class mail, facsimile, electronic mail, courier or other form of personal delivery at following addresses:

   The Secretary, Dispute Resolution Panel

   120 Adelaide Street West, Suite 1600

   Toronto, ON

   M5H 1T1

   Fax number: 416-506-2843

   Email: IESO-LegalServices@ieso.ca

All information submitted in this process will be used by the IESO solely in support of its obligations under the "Electricity Act, 1998", the "Ontario Energy Board Act, 1998", the "Market Rules" and associated policies, standards and procedures and its licence. All information submitted will be assigned the appropriate confidentiality level upon receipt.

Terms and acronyms used in this Form that are italicized have the meanings ascribed thereto in Chapter 11 of the "Market Rules"

Name and Address of *Respondent:*

Party Name:	Independent Electricity System Operator - MACD
Street Address:	120 Adelaide Street West, Suite 1600
City, Province:	Toronto, ON
Postal Code:	M5H 1T1
Telephone Number:	
Fax Number:	

-and-

Name and Address of Other *Respondent* (if any):
Party Name:
Street Address:
City, Province:
Postal Code:
Fax Number:

Part 1 – General Information about the *Applicant*

Organization Name: Nexus Energy Inc.	
Address: 4789 Yonge Street, Suite 916	
City/Town: Toronto	Province/State: ON
Postal/Zip Code: M2N 0G3	Country: Canada
Main Contact	
Name: Ali Qaisar	Title: General Counsel
Telephone No.: 437-238-6128	E-mail Address: ali.qaisar@nexusenergy.com
Market Participant/Metering Service Provider No.: 186267	IESO Customer Relations Ticket No. (if available):

Dispute Number:	(to be assigned by IESO upon receipt) A1707

Alternate Contact (if any)

Name: Reena Goyal	Title: Counsel
Telephone No.: 4168635807	E-mail Address: reena.goyal@blakes.com
Fax Number:	

Part 2 – Information about the Dispute

Is there a section of the Market Rules involved in the dispute?

☒Yes ☐ No

Please cite the Market Rules section number(s):

Chapter 3, sections 2.2.1.1, 2.6.2, 6.6.10A and 6.2.7.4

Chapter 7, sections 7.5.8A and 7.5.8B

Please cite the basis for the dispute:

See Parts 3 and 4.

If a settlement statement re-calculation is requested, please indicate the contested amount.

$2,078,824.92

Part 3 – Detailed Description of *Dispute*

A1708

This description **must** include:

- The nature and the basis for the complaint;
- The *Market Rules* at issue;
- The parties to the dispute and the name of any person having knowledge of, or who may be directly affected by, the dispute;
- A concise summary of the facts underlying the dispute;
- The relief sought and a summary of the grounds for such relief; and
- A description of any documentation on which the *applicant* intends to rely in support of its claim. Copies of the documentation may, but need not, be provided as part of the *Notice of Dispute*.

("Market Rules", Chapter 3, Section 2.5)

Part 3 – Detailed Description of *Dispute (continued)*

On December 17, 2024, MACD issued a notice of non-compliance with sanction assessment and order (together, the "IESO Order"). The IESO Order requires the adjustment of settlement amounts relating to Nexus Energy to, inter alia, recover "congestion rents" in allegedly avoided by Nexus Energy in relation to the subject transactions.

Nexus Energy disputes that "avoided congestion rents" constitute "settlement amounts" that may be recovered under Chapter 3, section 6.6.10A of the Market Rules or at all.

Alternatively, even if "avoided congestion rents" may be recovered by the IESO, Nexus Energy disputes that the circumstances surrounding the subject transactions warrant action under Section 6.6.10A. Further, it is Nexus Energy's position that the manner in which MACD has approached the issue of failed intertie transactions in general, and in Nexus Energy's case in particular, is contrary to its mandate to foster compliance in the wholesale electricity market in Ontario and is discriminatory and unfairly prejudicial to Nexus Energy.

Nexus Energy requests the IESO Order be set aside to the extent that it requires the adjustment of settlement amounts on account of "avoided congestion rents".

Persons who may knowledge of the dispute include, but are not limited to:

1. Ali Qaisar - General Counsel, Nexus Energy
2. Francois Tardif - Director, Risk & Regulatory Affairs, Nexus Energy
3. Robin Doolittle - Managing Director, Trading & Marketing, Nexus Energy

4. William Mercer - Head of Physical Trading, Nexus Energy

5. Bob Yeoman - Sr. Manager, Rule Enforcement, MACD

6. Egor Sitnik - Supervisor, Compliance Investigations, MACD

7. John Koetsier - Senior Analyst, MACD

Documentation that Nexus Energy intends to rely on includes, but is not limited to:

1. IESO Notice of Alleged Breach dated April 4, 2024

2. Nexus Energy's written response dated July 9, 2024 to the Notice of Alleged Breach, and all historical IESO materials referenced therein

3. IESO Notice of Non-Compliance dated December 17, 2024, including IESO order

4. Monitoring Reports issued by the Market Surveillance Panel of the Ontario Energy Board from 2010 through to the present day.

5. MACD Intertie Transactions Failures Guidelines document dated 18 November 2005.

6. Market Rules Amendment Proposal MR-00308-R00 approved February 7, 2006.

7. IESO Stakeholder Engagment Session presentation entitled "Interchange schedule code: MrNH" dated May 22, 2024.

8. IESO Stakeholder Engagement Session presentation entitled "Preparing for the Launch of the Renewed Market - Intertie Traders and Tansmission Rights Auction Participants" dated April 10, 2025.

A1710

Part 4 – Summary of *Dispute*

Please summarize the information provided in Part 3. This section must be completed if the good faith negotiations fail to resolve the dispute between the parties. This summary will be posted on the publically available *IESO* Web site in the event that the dispute proceeds to arbitration. ("Market Rules", Chapter 3, Section 2.5)

On December 17, 2024, the Markets Assessment and Compliance Division ("MACD") of the Independent Electricity System Operator ("IESO") issued a notice of non-compliance A1711 alleging that Nexus Energy Inc. ("Nexus") had breached the IESO's market rules with respect to certain failed scheduled intertie transac-tions over a period spanning from December 2017 up to and including December 2023 ("IESO Order"). The subject transactions constituted a small percentage of transactions scheduled by Nexus during the relevant period and Nexus did not receive any significant transmission rights benefits or other revenues as a result of the failed transactions. The IESO has not assessed any penalties or sanctions against Nexus with respect to said failed intertie transactions and is instead seeking to affect a settlement ad-justment to recover "congestion rents" allegedly avoided by Nexus when those intertie transactions failed, as those congestion rents are not included in the calculation of the over $1.6 million in failure charges already paid by Nexus to the IESO for the benefit of market participants in the Ontario wholesale electricity market.

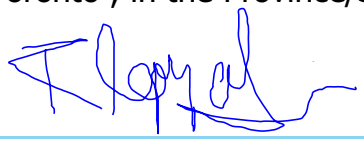
Nexus Energy disputes the authority of the IESO to recover "avoided congestion rents" under the market rules with respect to the subject failed transactions. Alternatively, even if "avoided congestion rents" may be recovered by the IESO, Nexus Energy disputes that the circumstances surrounding the subject trans-actions warrant such action based on a purposive interpretation of the relevant market rules.

Furthermore, the IESO has breached its obligations of procedural fairness under Chapter 3 of the market rules. Following Nexus' filing a notice of dispute with the IESO on February 11th, 2025 challenging the lawfulness of the IESO Order, IESO Legal Services altogether failed to participate in the dispute resolution process – including negotiations and mediation as prescribed under the market rules - and MACD failed to participate in mediation in good faith. More specifically, MACD failed to prepare a proper mediation brief and failed to attend mediation with any willingness to compromise or to meaningfully participate in a negotiated resolution (while at the same time failing to offer to dispense with mediation and instead requiring Nexus to incur unnecessary costs).

Part 5 – Declaration

The undersigned, a duly authorized representative of the *applicant*, hereby declares that the information contained in and submitted in support of this *Notice of Dispute* is, to the best of the *applicant's* knowledge, complete and accurate.

Dated at the City of Toronto , in the Province/State of Ontario, this 21 day of May, 2025.

Signature: 

Name: Ali Qaisar (per Reena Goyal)

Title: General Counsel

I have authority to bind the *applicant.*

Please attach a copy of any documents that you wish to provide in support of the claims made in this *Notice of Dispute*.

Attachments Included:

☐ Yes ☒ No

Total Number of Pages (including this *Notice of Dispute* and all attachments): 7

Exhibit "I"

OEB electricity wholesaler licence issued to Nexus Energy on September 13, 2022

Exhibit "I"

to the Affidavit of Francois Tardif

Sworn before me on October 29, 2025, in accordance with O. Reg. 431/20,
Administering Oath or Declaration Remotely



Commissioner for Taking Affidavits
(or as may be)

October 29, 2025

Keith Edward Hickey, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.

Expires June 24, 2027.

Electricity Wholesaler Licence

EW-2022-0193

Nexus Energy Inc.

Valid Until

September 12, 2027

Brian Hewson
Vice President, Consumer Protection & Industry Performance
Ontario Energy Board
Date of Issuance: September 13, 2022

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
27th Floor
Toronto, ON M4P 1E4

Commission de l'énergie de l'Ontario
C.P. 2319
2300, rue Yonge
27e étage
Toronto ON M4P 1E4

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2	Interpretation	1
3	Authorization	1
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5	Provision of Information to the Board	2
6	Term of Licence	2
7	Fees and Assessments	2
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9	Copies of the Licence	2
SCHEDULE 1	AUTHORIZED TRADE NAMES	3

1 Definitions

In this Licence:

"Act" means the *Ontario Energy Board Act, 1998,* S.O. 1998, c. 15, Schedule B;

"Electricity Act" means the *Electricity Act, 1998, S.O. 1998,* c. 15, Schedule A;

"Licensee" means Nexus Energy Inc.;

"regulation" means a regulation made under the Act or the Electricity Act; and

"wholesaler" means a person who purchases electricity or ancillary services in the IESO-administered markets or directly from a generator or who sells electricity or ancillary services through the IESO-administered markets or directly to another person, other than a consumer.

2 Interpretation

2.1 In this Licence words and phrases shall have the meaning ascribed to them in the Act or the Electricity Act. Words or phrases importing the singular shall include the plural and vice versa. Headings are for convenience only and shall not affect the interpretation of this Licence. Any reference to a document or a provision of a document includes an amendment or supplement to, or a replacement of, that document or that provision of that document. In the computation of time under this Licence where there is a reference to a number of days between two events, they shall be counted by excluding the day on which the first event happens and including the day on which the second event happens. Where the time for doing an act expires on a day that is a holiday, the act may be done on the next day that is not a holiday.

3 Authorization

3.1 The Licensee is authorized, under Part V of the Act and subject to the terms and conditions set out in this licence:

a) to purchase electricity or ancillary services in the IESO-administered markets or directly from a generator subject to the conditions set out in this Licence; and

b) to sell electricity or ancillary services through the IESO-administered markets or directly to another person other than a consumer, subject to the conditions set out in this Licence.

3.2 The Licensee is authorized to conduct business in the name under which this Licence is issued, or any trade name(s) listed in Schedule 1.

4 Obligation to Comply with Legislation, Regulations and Market Rules

4.1 The Licensee shall comply with all applicable provisions of the Act and the Electricity Act, and regulations under these Acts, except where the Licensee has been exempted from such compliance by regulation.

4.2 The Licensee shall comply with all applicable Market Rules.

5 Provision of Information to the Board

5.1 The Licensee shall maintain records of and provide, in the manner and form determined by the Board, such information as the Board may require from time to time.

5.2 Without limiting the generality of paragraph 5.1 the Licensee shall notify the Board of any material change in circumstances that adversely affects or is likely to adversely affect the business, operations or assets of the Licensee as soon as practicable, but in any event no more than twenty (20) days past the date upon which such change occurs.

6 Term of Licence

6.1 This Licence shall take effect on September 13, 2022 and expire on September 12, 2027. The term of this Licence may be extended by the Board.

7 Fees and Assessments

7.1 The Licensee shall pay all fees charged and amounts assessed by the Board.

8 Communication

8.1 The Licensee shall designate a person that will act as a primary contact with the Board on matters related to this Licence. The Licensee shall notify the Board promptly should the contact details change.

8.2 All official communication relating to this Licence shall be in writing.

8.3 All written communication is to be regarded as having been given by the sender and received by the addressee:

a) when delivered in person to the addressee by hand, by registered mail or by courier;

b) ten (10) business days after the date of posting if the communication is sent by regular mail; or

c) when received by facsimile transmission by the addressee, according to the sender's transmission report.

9 Copies of the Licence

9.1 The Licensee shall:

a) make a copy of this Licence available for inspection by members of the public at its head office and regional offices during normal business hours; and

b) provide a copy of this Licence to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

SCHEDULE 1 AUTHORIZED TRADE NAMES

1. None

Exhibit “J”

Ontario Energy Board “Who We Are” webpage

Exhibit “J”

to the Affidavit of Francois Tardif

Sworn before me on October 29, 2025, in accordance with O. Reg. 431/20,
Administering Oath or Declaration Remotely



Commissioner for Taking Affidavits
(or as may be)

October 29, 2025

Keith Edward Hickey, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.

Expires June 24, 2027.

- Public tenders

  Public tenders
- Resource centre

  Resource centre

Who we are

We are Ontario's independent regulator of the electricity and natural gas sectors. We protect consumers and make decisions that serve the public interest. Our goal is to promote a sustainable and efficient energy sector, for today and tomorrow. We are an independent entity with a Board of Directors, a Chief Executive Officer, Chief Corporate Services Officer & General Counsel, Chief Operating Officer and Commissioners led by a Chief Commissioner.

- See our Board of Directors
- See our Executive Leadership team
- See our Commissioners

How we're structured

Our Board of Directors is appointed by the Lieutenant Governor in Council. Our Chief Executive Officer and Commissioners are appointed by our Board of Directors.

The Board of Directors oversees the management of the OEB's business and affairs, and is responsible for the governance of the OEB. The Chair of the Board of Directors is accountable to the Minister of Energy and Mines for the effective delivery of the OEB's mandate and for ensuring the independence of decision-making by Commissioners and others that carry out the OEB's adjudication work. Read the OEB's statement on independence. The Board of Directors has established committees to assist in carrying out its oversight role:

- The Adjudication Committee receives information from the Chief Commissioner on the efficiency and timeliness of our adjudication work, and reports that information to the Board of Directors.
- The Finance & Risk Committee provides oversight and recommendations to the Board of Directors on risk management and financial affairs, including reporting, disclosure, compliance, enterprise risk management and internal audit at the OEB.

The Chief Executive Officer (CEO) reports to the Board of Directors and is responsible for the efficient and effective management and operations of the OEB, leading the Executive Leadership Committee in implementing the OEB's operations and in developing, implementing and reporting to the Board of Directors on the OEB's operations. The CEO is also tasked with making electricity Codes and natural gas Rules that govern the operations of many of the entities that we regulate. The Executive Leadership Committee consists of the CEO, the Chief Commissioner, the Chief Corporate Services Officer & General Counsel and the Chief Operating Officer.

The Chief Commissioner is responsible for ensuring the efficiency and timeliness of the OEB's adjudication work, assigning Commissioners to preside over hearings and making Rules of Practice and Procedure that govern the hearing process. The Chief Commissioner reports to the Chief

Executive Officer on the efficiency and timeliness of our adjudication work. Commissioners are responsible for making independent decisions on applications and other hearing matters that come before the OEB and to which they are assigned by the Chief Commissioner.

The Chief Corporate Services Officer & General Counsel provides executive leadership to the teams in People, Culture & Strategic Policy, Finance, Information Technology, Legal Services and Public Affairs.

The Chief Operating Officer provides executive leadership to the teams in Applications, Consumer Protection & Industry Performance, Office of the Registrar and Operations Decision Support.

Industry Menu

- Who we are

  Who we are
  - Board of Directors
  - Executive leadership
  - Commissioners
- Mission and mandate

  Mission and mandate
- What we do

  What we do
- Corporate governance and reports

  Corporate governance and reports
- Careers

  Careers
- Public tenders

  Public tenders
- Resource centre

  Resource centre

Was this page helpful?
Yes
No
Please tell us why, to help us improve:
Language is too technical
Too much information
Not enough information
I don't like the way the page looks
Other

Exhibit “K”

Ontario Energy Board “Market surveillance panel” webpage

Exhibit “K”

to the Affidavit of Francois Tardif

Sworn before me on October 29, 2025, in accordance with O. Reg. 431/20,
Administering Oath or Declaration Remotely



_____

Commissioner for Taking Affidavits
(or as may be)

October 29, 2025

Keith Edward Hickey, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.

Expires June 24, 2027.

Market surveillance panel

The Market Surveillance Panel monitors, investigates and reports on activities and behaviour in the IESO-administered markets in Ontario's electricity sector. IESO stands for Independent Electricity System Operator.

The Panel’s specific responsibilities include:

- Monitoring activities and behaviour and recommending remedial action

- Investigating market activities and the behaviour of specific energy companies or energy-related agencies (for example, if they are suspected of gaming or abusing their market power) and making recommendations related to the results of its investigations
- Reporting on the results of its monitoring and investigations

Transfer from the IESO to the Ontario Energy Board

Under the *Electricity Restructuring Act, 2004*, the Market Surveillance Panel transferred to the Ontario Energy Board from the IESO, effective January 1, 2005.

Section 4.3.1 of the *Ontario Energy Board Act, 1998* provides the statutory basis for the continuation of the Market Surveillance Panel, while Section 37 of the *Electricity Act, 1998*, establishes the Panel's statutory powers of investigation. The mandate of the Panel is set out in Ontario Energy Board By-law #2 (pdf).

The Ontario Energy Board and the IESO Protocol

The Ontario Energy Board and the IESO have entered into a Protocol (pdf). Under the Protocol, the IESO's market assessment unit will continue to assist the Market Surveillance Panel, which is a Panel of the Ontario Energy Board.

The Protocol also provides for the Market Surveillance Panel to continue to assist and advise the IESO on various matters arising under the market rules and addresses issues relating to confidentiality and the exchange of information. The Protocol came into effect on April 25, 2005 for a period of one year. The Protocol was previously renewed for successive two-year or six-month terms, but as of May 1, 2017 it will be automatically renewed for successive two-year terms unless either Party gives notice of its intention not to renew.

Panel Members

The members of the Panel bring with them broad experience and expertise in economics, competition law, corporate governance, public policy and the electricity industry:

Ken Quesnelle is the Chair of the Panel. He was the Vice Chair of the OEB from February 2014 to September 2018, following a tenure of almost nine years as a full-time Board Member. Prior to his appointment to the OEB, Mr. Quesnelle worked in various positions in the electricity distribution sector and is a past Chair of the Electricity Distributors Association. He has over 30 years of experience in the utility and municipal administration business, which includes electricity and water distribution as well as water supply and related environmental protection. Mr. Quesnelle is a past Chair of CAMPUT – Canada's Energy and Utility Regulators – and was a member of the International Confederation of Energy Regulators and Chair of its Technology and Innovation working group. Mr. Quesnelle was also an Executive Committee member of the Advisory Council of the Electric Power Research Institute.

Brian Rivard is an Adjunct Professor at the Richard Ivey School of Business, Western University, and holds a PhD and a Master of Economics from the University of Western Ontario. His area of expertise and study is electricity market design and regulation. He has experience as an energy consultant, most recently as a Principal at Charles River Associates, and has provided expert testimony before the US Federal Energy Regulatory Commission and the OEB. Through his earlier

work for the IESO over almost 15 years, Brian helped support the development of market-based approaches to managing Ontario's electricity system needs, and as the IESO's Director of Markets was responsible for providing analysis of the impacts of changes to the IESO Market Rules, Market Design, government policies and other industry initiatives. Prior to that, he was a senior economist with the Canadian Competition Bureau for several years.

Darren Finkbeiner has nearly four decades of experience in Ontario's electricity sector, spending the majority of his career with the IESO and its predecessor, Ontario Hydro. He was one of the original architects of Ontario's wholesale electricity market and a representative on the IESO Board's Technical Panel. Retiring from the IESO as the Director of Rule Compliance & Market Surveillance, Mr. Finkbeiner previously held senior positions in the IESO's power system operations, operational effectiveness, market rules and evolution functions as well as multi-agency roles responsible for government policy implementation and contract negotiation. He has provided expert testimony at the OEB, as well as an Ontario and Canadian perspective to regulators and market monitors nationally and internationally. These contributions include representations before the U.S. Federal Energy Regulatory Commission, the North American Electric Reliability Corporation and market monitors from across the globe, including a secondment with the Australian Energy Regulator. Most recently, he has been providing consulting services in the areas of reliability standards enforcement and international co-operation agreements.

Information confidentiality

Section 4.3.1(8) of the *Ontario Energy Board Act, 1998*, confirms that information that is held by the Market Surveillance Panel and that is designated by the Panel as "confidential" or "highly confidential" is confidential third party information for access to information purposes. Section 8.3.1 of the OEB Bylaw # 3 preserves the confidential or highly confidential status of documents or records so classified by the IESO prior to January 1, 2005. Some information relating to the confidentiality classification of market surveillance-related documents may no longer be available on the IESO website. To ensure that market participants do not lose access to this information, it is being posted on the OEB's Market Surveillance Panel web pages.

The first item is the IESO's Information Confidentiality Catalogue. The relevant parts of this document are page 67 (beginning at ID 469) to page 72 (ending at ID 691).

In order to put the above document in context, the market surveillance-related pages of the IESO's Market Rules as at December 31, 2004 are available here. They can be found on pages 3-28 to 3-39 of Chapter 3 of the Market Rules.

FAQs

What does the MSP monitor and investigate?
The MSP, with the support of the IESO's market assessment unit, monitors and investigates activities within the IESO-administered markets and the conduct of market participants relating to:

- inappropriate market conduct, including possible abuses of market power and gaming
- design flaws and inefficiencies in the market rules and other rules and procedures of the IESO
- design flaws in the overall structure of the IESO-administered markets

How does the MSP monitor activities and market participant conduct in the IESO-administered markets?
The MSP is supported by the IESO's market assessment unit, which has developed a sophisticated surveillance data repository to monitor activities and market participant conduct in the IESO-administered markets. Internal and external data will be aggregated on a frequent and timely basis by the market surveillance system. This data is used as the first step to assess market activity and market participant conduct.

Does the Market Surveillance Panel have the authority to launch an investigation on its own?
The Market Surveillance Panel does not require prior concurrence when launching an investigation into any activity related to the IESO-administered markets or the conduct of a market participant.

Can market participants or other parties request the Market Surveillance Panel to launch an investigation?
Any person requesting an investigation into market activities or conduct may do so by setting out in writing:

- the name and address of the complainant or person referring the matter
- the particulars of the complaint or referral
- any information or facts supporting the complaint or referral
- the signature of the person making the complaint or referral or the signature of an officer or duly authorized representative of the person

Can the Market Surveillance Panel decide not to commence or terminate an investigation once a complaint or referral has been received?
The Market Surveillance Panel may refuse to commence or decide to terminate an investigation because the complaint or referral is either: frivolous, vexatious or not material, or because it is within the jurisdiction of another person, board, agency or tribunal. A decision by the Panel not to commence or continue an investigation is subject to review by the Chair of the OEB.

Where can I find out more information about local market power?
The IESO has a process in place to mitigate the effect of Local Market Power. Market Manual 2.12: Treatment of Local Market Power provides detailed information about the local market power mitigation process and the price screening mechanism used to determine compensation for power generators affected by congestion of the grid.

Are all market surveillance reports public documents?
Market surveillance reports will be published in accordance with the OEB's Bylaw #2. Reports may be edited to remove confidential information before being made public.

Where do I get more information?
For more information, contact OEB Industry Relations:

Tel: 416-440-7604 or 1-888-632-6273 (toll-free)
Email: IndustryRelations@oeb.ca

Exhibit “L”

Ontario Energy Board By-Law #2

Exhibit “L”

to the Affidavit of Francois Tardif

Sworn before me on October 29, 2025, in accordance with O. Reg. 431/20,
Administering Oath or Declaration Remotely



Commissioner for Taking Affidavits
(or as may be)

October 29, 2025

Keith Edward Hickey, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.

Expires June 24, 2027.

ONTARIO ENERGY BOARD

BY-LAW #2
MARKET SURVEILLANCE PANEL

BE IT ENACTED as a By-law of the Board as follows:

ARTICLE 1
INTERPRETATION

1.1 Definitions

1.1.1 In this By-law, unless the context otherwise requires:

"**Act**" means the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B;

"**Board**" means the Ontario Energy Board continued under the Act as a corporation without share capital under the name Ontario Energy Board in English and Commission de l'énergie de l'Ontario in French;

"**Board Chair**" means the Director appointed by the Lieutenant Governor in Council as Chair of the Board of Directors under section 4.1(8) of the Act;

"Board of Directors" means the board of directors of the Board under section 4.1 of the Act;

"CEO" means the chief executive officer under section 4.2 of the Act, whether appointed by the Lieutenant Governor in Council or the Board of Directors;

"**confidential information**" means information that is not public and that is in its nature confidential, proprietary or commercially sensitive;

"**Director**" means a member of the Board of Directors;

"**Electricity Act**" means the *Electricity Act, 1998*, S.O. 1998, c. 15, Sched. A;

"**employee**" means any person employed by another person, whether on a permanent basis, on a fixed term contract or on secondment, and

includes (a) a probationary employee, (b) a temporary employee, and (c) in the case of the Board, a Crown employee providing services to the Board under an agreement contemplated in section 4.16(4) of the Act, but does not include a Member of the Board or a member of the Panel;

"**IESO**" has the meaning given to it in the Electricity Act;

"**market manual**" has the meaning given to it in the market rules;

"**market rules**" means the rules made under section 32 of the Electricity Act;

"**MAU**" means the market assessment unit established by the IESO;

"**Member of the Board**" means the individuals who compose the Board under section 4(5) of the Act;

"**Monitoring Document**" has the meaning given to it in section 4.2.1;

"**Panel**" means the Market Surveillance Panel continued as the Market Surveillance Panel of the Board under the Act;

"**Panel Chair**" means the person appointed under section 2.4 as the chair of the Panel; and

"**Protocol**" means a protocol or agreement between the Board and the IESO relating to the use by the Panel of the services of employees of the IESO, including employees forming part of the MAU, and to such other matters as may be required to give effect to this By-law.

1.2 Interpretation and Severability

1.2.1 Except as provided in section 1.1.1, words and expressions that are defined in the Act or the Electricity Act have the same meanings when used in this By-law.

1.2.2 In this By-law:

(a) words importing the singular number include the plural and vice versa;

(b) words importing a gender include the masculine, feminine and neuter genders;

(c) words importing a person include an individual, a sole proprietorship, a partnership, an unincorporated association, an unincorporated syndicate, an unincorporated organization, a trust, a

body corporate and a natural person in their capacity as trustee, executor, administrator or other legal representative;

(d) except where the context otherwise requires, a reference to an Article, section or paragraph is to an Article, section or paragraph of this By-law;

(e) a reference to any statute, regulation, proclamation, order in council, ordinance, by-law, resolution, rule, order or directive includes all statutes, regulations, proclamations, orders in council, ordinances, by-laws, resolutions, rules, orders or directives varying, consolidating, re-enacting, extending or replacing it;

(f) a reference to a document, including a statute, includes an amendment or supplement to, or replacement of, that document, as well as any schedule, appendix or other annexure thereto;

(g) a reference to a statute includes any regulation made under that statute;

(h) the expression “including” means including without limitation, and the expression “include”, “includes” and “included” shall be interpreted accordingly; and

(i) a list of elements preceded by the word “includes”, “including”, “such as” or similar language shall not be interpreted as excluding any other element, whether of the same or a different nature or scope.

1.2.3 Headings are included in this By-law for reference purposes only and are not to be considered or taken into account in construing the terms of provisions of this By-law.

1.2.4 The invalidity or unenforceability of any provision of this By-law shall not affect the validity or enforceability of the remaining provisions of this By-law.

ARTICLE 2
COMPOSITION, APPOINTMENT, REAPPOINTMENT, REMOVAL, REMUNERATION AND INDEMNIFICATION

2.1 Composition, Appointment and Qualification

2.1.1 The Panel shall consist of at least three qualified persons. The quorum for the transaction of business at any meeting of the Panel consists of a majority of members. At all meetings of the Panel every question shall be

decided by a majority of the votes cast on the question. In the case of an equality of votes, the Panel Chair will be entitled to a second or casting vote. Where there is a vacancy or vacancies in the Panel, the remaining members may exercise all the powers of the Panel so long as a quorum of the Panel remains in office.

2.1.2 Subject to section 2.1.3, the Board of Directors shall from time to time appoint the members of the Panel.

2.1.3 No person shall be appointed to the Panel if that person is disqualified under section 4.3.1(3) of the Act or under section 2.1.4.

2.1.4 The following persons are disqualified from being a member of the Panel:

(a) a person who is less than eighteen years of age;

(b) a person who is of unsound mind and has been so found by a court in Canada or elsewhere;

(c) a person who is not an individual;

(d) a person who has the status of a bankrupt;

(e) a person who is an employee of the Government of Ontario; or

(f) a Member of the Board.

2.1.5 No person shall be appointed to the Panel unless such person has:

(a) provided to the Board of Directors such certification as the Board of Directors may require attesting to the fact that the person is not disqualified under section 2.1.3 or 2.1.4; and

(b) entered into such agreement with the Board as the Board of Directors, on the advice of the CEO, determines appropriate in order to give effect to the provisions of this By-law.

2.1.6 The Board of Directors may from time to time require a member of the Panel to provide to the Board of Directors such certification as the Board of Directors may require attesting to the fact that the person has not become disqualified under section 2.1.3 or 2.1.4.

2.2 Term and Reappointment

2.2.1 Subject to section 2.2.2, a member of the Panel shall serve for a term of three years.

2.2.2 A person may be appointed under this By-law to serve for an initial term of more or less than three years or may be reappointed under this By-law to serve for a term of less than three years as the Board of Directors considers appropriate to ensure that the terms of two or more members of the Panel do not expire at or about the same time.

2.2.3 Subject to section 2.2.4, a member of the Panel may be reappointed by the Board of Directors for a further term of up to three years, provided that no person may serve on the Panel for more than ten consecutive years.

2.2.4 The term of a member of the Panel appointed to replace a predecessor member whose term had not yet expired shall be for the balance of the predecessor's term and shall not, provided such term is no greater than two years, be counted for purposes of determining the member's eligibility for reappointment.

2.3 Ceasing to Hold Office

2.3.1 The Board of Directors may remove any member of the Panel from office at any time, with or without cause, as the Board of Directors determines appropriate.

2.3.2 A member of the Panel ceases to hold office when the member:

(a) dies or resigns;

(b) is removed in accordance with section 2.3.1; or

(c) becomes disqualified under section 2.1.3 or 2.1.4.

2.4 Panel Chair

2.4.1 The Board of Directors, on the advice of the CEO, shall from time to time appoint a member of the Panel as Panel Chair. Where the office of Panel Chair is vacant, the Board of Directors, on the advice of the CEO, may appoint a member of the Panel as Acting Panel Chair pending appointment of a Panel Chair. Except as otherwise determined by the Board of Directors, on the advice of the CEO, the Acting Panel Chair shall have the same powers and perform the same duties as the Panel Chair.

2.4.2 The Panel Chair shall act as the designated representative of the Panel in relation to the Panel's relationship with the Board in such manner as the Board of Directors, on the advice of the CEO, determines appropriate.

2.5 Remuneration

2.5.1 Members of the Panel shall be paid such remuneration for their services as shall be fixed from time to time by the Board of Directors.

2.5.2 Members of the Panel shall be entitled to be reimbursed for expenses properly and actually incurred by them in connection with the performance of their duties.

2.6 Code of Conduct/Conflict of Interest

2.6.1 The Board of Directors, on the advice of the CEO, may adopt a code of conduct and conflict of interest guidelines applicable to members of the Panel. Members of the Panel shall comply with such code of conduct and conflict of interest guidelines.

2.7 Indemnification

2.7.1 Subject to any limitations contained in the Act or any other statute, the Board shall indemnify a member of the Panel, a former member of the Panel and the heirs and legal representatives of a member or former member of the Panel, against all costs, charges and expenses, including an amount paid to settle an action or satisfy a judgment, reasonably incurred by them in respect of any civil, criminal, administrative, investigative or other action or proceeding in which the individual is involved by reason of being a member or former member of the Panel.

2.7.2 The Board shall advance moneys to any member or former member of the Panel for the costs, charges and expenses of a proceeding referred to in that section. The member or former member of the Panel shall repay the moneys if they do not fulfil the conditions of section 2.7.3.

2.7.3 The Board shall not indemnify a member or former member of the Panel under section 2.7.1 or 2.7.2 unless the individual:

(a) acted honestly and in good faith with a view to the best interests of the Board; and

(b) in the case of a criminal or administrative action or proceeding that is enforced by a monetary penalty, the individual had reasonable grounds for believing that their conduct was lawful.

2.7.4 The Board shall also indemnify a member or former member of the Panel in such other circumstances as the Act or other law permits or requires. Nothing in this By-law shall limit the right of any individual entitled to indemnity to claim indemnity apart from the provisions of this By-law.

2.7.5 Subject to the Act and any other statute, the Board may execute agreements evidencing its indemnity in favour of a member or former member of the Panel against such liabilities as the Board of Directors may from time to time determine.

ARTICLE 3
PANEL DUTIES, ASSISTANCE, PROTOCOL, AUDIT AND PANEL WEB PAGE

3.1 Duties

3.1.1 The Panel shall have the duties and perform the activities assigned to it in the Electricity Act and under sections 3.1.2 to 3.1.7.

3.1.2 The Panel shall direct the work of and supervise the MAU in accordance with and to the extent provided in the Protocol.

3.1.3 The Panel shall monitor activities related to the IESO-administered markets and the conduct of market participants in accordance with Article 4.

3.1.4 The Panel shall conduct investigations into activities related to the IESO-administered markets or the conduct of a market participant in accordance with Article 5.

3.1.5 The Panel shall conduct reviews of the IESO-administered markets in accordance with Article 6.

3.1.6 The Panel may provide such advice or assistance to the IESO as the IESO may request on matters that arise under the market rules, as more specifically set out in, and in accordance with the provisions of, the Protocol.

3.1.7 The Panel shall perform such other activities or functions as the CEO may assign to it in relation to the surveillance of electricity markets.

3.2 Assistance to the Panel

3.2.1 The Panel may, with the prior concurrence of the CEO, use the services of employees of the Board.

3.2.2 The Panel may, with the prior concurrence of the CEO, use the services of other persons having technical or professional expertise that the Panel considers necessary for the fulfillment of its duties.

3.2.3 The Panel shall comply with such restrictions and conditions as may be imposed by the CEO in relation to the use of the services referred to in sections 3.2.1 and 3.2.2.

3.3 Protocol

3.3.1 A member of the Panel shall comply with all provisions of the Protocol that apply to members of the Panel.

3.3.2 A member of the Panel shall promptly notify the CEO of:

(a) any violation of the Protocol by any person; and

(b) any perceived inefficiencies or difficulties in relation to the application of the Protocol.

3.4 Audit

3.4.1 The activities of the Panel shall be audited in accordance with such procedures as may be adopted from time to time by the CEO.

3.5 Panel Web Page

3.5.1 The Board shall maintain a page on its website for the purpose of posting:

(a) written reports and other documents required by this By-law to be posted on the Board's website;

(b) the manner in which persons may contact a member of the Panel; and

(c) such other information as the CEO considers appropriate in relation to the Panel and the duties of the Panel.

ARTICLE 4
MONITORING

4.1 Monitoring

4.1.1 The Panel shall monitor, evaluate and analyse activities related to the IESO-administered markets and the conduct of market participants with a view to:

(a) identifying inappropriate or anomalous market conduct by a market participant, including unilateral or interdependent behaviour

resulting in gaming or in abuses or possible abuses of market power;

(b) identifying activities of the IESO that may have an impact on market efficiencies or effective competition;

(c) identifying actual or potential design or other flaws and inefficiencies in the market rules and in the rules and procedures of the IESO;

(d) identifying actual or potential design or other flaws in the overall structure of the IESO-administered markets and assessing whether any one or more specific aspects of the underlying structure of the IESO-administered markets is consistent with the efficient and fair operation of a competitive market; and

(e) recommending remedial actions to mitigate the conduct, flaws and inefficiencies referred to in paragraphs (a) to (d).

4.1.2 For the purpose of carrying out the monitoring, evaluation and analysis activities referred to in section 4.1.1, the Panel has the power to compel the production of information from a market participant and to enter upon the premises of a market participant as authorized by the Electricity Act.

4.1.3 The Panel shall prepare and deliver reports in relation to its activities under this section 4.1 in accordance with sections 7.1 and 7.5.

4.2 Monitoring Documents

4.2.1 The Panel shall adopt and from time to time amend as required the following documents (each a “Monitoring Document”):

(a) a detailed catalogue of all of the data and/or categories of data that the Panel or the MAU will have the need or means of acquiring directly from market participants;

(b) a catalogue of the monitoring indices that the Panel or the MAU will use to analyze the data so required; and

(c) such other information requirements and evaluation criteria as the Panel considers appropriate for the purpose of enabling it to effectively carry out the monitoring function referred to in section 4.1.1.

4.2.2 Prior to adopting or amending a Monitoring Document under section 4.2.1, the Panel shall provide a copy of the Monitoring Document or amendment

to the CEO. Subject to section 4.2.3, the CEO shall cause such Monitoring Document or amendment to be posted on the Board's website. Such posting shall be accompanied by a notice inviting the IESO and market participants to comment on the Monitoring Document or amendment within the time indicated in the notice.

4.2.3 No Monitoring Document referred to in paragraph 4.2.1(b) or 4.2.1(c) nor any amendment to such Monitoring Document shall be posted on the Board's website for comment under section 4.2.2 if the CEO, on the advice of the Panel, determines that such posting is reasonably likely to compromise the work of the MAU or the Panel.

4.2.4 The Panel retains the discretion to adopt a Monitoring Document or an amendment to a Monitoring Document notwithstanding any comments received in opposition thereto.

4.2.5 Where the Panel adopts or amends a Monitoring Document, the Panel shall provide a copy of the Monitoring Document or amendment to the CEO. Subject to section 4.2.6, the CEO shall cause such Monitoring Document or amendment to be posted on the Board's website.

4.2.6 No Monitoring Document referred to in paragraph 4.2.1(b) or 4.2.1(c) nor any amendment to such Monitoring Document adopted by the Panel under this section 4.2 shall be posted on the Board's website if the CEO, on the advice of the Panel, determines that such posting is reasonably likely to compromise the work of the MAU or the Panel.

4.2.7 Nothing in this section 4.2 shall be interpreted as precluding the Panel from undertaking such monitoring, evaluation or analysis as the Panel determines appropriate for the purposes of carrying out the monitoring activities referred to in section 4.1.1.

4.2.8 A Monitoring Document or an amendment to a Monitoring Document adopted by the Market Surveillance Panel of the Independent Electricity Market Operator prior to the date of coming into force of section 4.3.1(1) of the Act and included in a market manual prior to that date shall be deemed to have been adopted by the Panel under this By-law. Such Monitoring Document or amendment shall be posted on the Board's website.

ARTICLE 5
INVESTIGATIONS

5.1 Investigations

5.1.1 The Panel may conduct an investigation into any activities related to the IESO-administered markets or the conduct of a market participant:

(a) where the Panel considers such investigation to be warranted as a result of the monitoring activities referred to in section 4.1.1 or as a result of a review referred to in Article 6;

(b) upon receipt of a complaint or referral under section 5.1.3; or

(c) upon being requested to do so by the CEO.

5.1.2 Where the Panel intends to commence an investigation under paragraph 5.1.1(a) or 5.1.1(b), the Panel shall so notify the CEO.

5.1.3 Any person other than the CEO acting under paragraph 5.1.1(c) that wishes the Panel to conduct an investigation into any matter referred to in section 5.1.1, or any board, agency or tribunal that wishes to refer any such matter to the Panel for investigation, shall make a complaint or referral in writing setting out:

(a) the name and address of the complainant or person referring the matter;

(b) the particulars of the complaint or referral;

(c) any information or facts supporting the complaint or referral; and

(d) the signature of the person making the complaint or referral or, where that person is not an individual, the signature of a duly authorized representative of the person.

5.1.4 The Panel may refuse to commence an investigation into any complaint or matter referred to it under section 5.1.3 where the Panel determines that:

(a) the complaint or referral is frivolous, vexatious or otherwise not material; or

(b) the subject matter of the complaint or referral is within the jurisdiction of another person, board, agency or tribunal.

5.1.5 The Panel may, once it has commenced an investigation into any complaint or matter referred to it under section 5.1.3, terminate that investigation where the Panel determines that:

(a) the complaint or referral is frivolous, vexatious or otherwise not material; or

(b) the subject matter of the complaint or referral is within the jurisdiction of another person, board, agency or tribunal.

5.1.6 The Panel may, prior to making a determination under section 5.1.4 or 5.1.5, request that the person making the complaint or referral provide additional information relating to the complaint or referral.

5.1.7 Where the Panel makes a determination under section 5.1.4 or 5.1.5, the Panel shall notify the CEO in writing of the determination and of the reasons for the determination. The CEO shall, unless the CEO gives a direction to the Panel under section 5.1.8, notify the following of the Panel's determination:

(a) the person that filed the complaint or referral; and

(b) where the investigation relates to the conduct of a person, the person that is the subject matter of the investigation.

5.1.8 The Panel shall, upon being directed to do so by the CEO:

(a) commence an investigation that the Panel had previously determined not to commence under section 5.1.4; or

(b) resume an investigation that the Panel had terminated under section 5.1.5.

5.1.9 Where the Panel has commenced an investigation, the Panel shall upon determining that there is a *prima facie* case in respect of the conduct of a person that is the subject matter of the investigation, notify that person of the commencement of the investigation. The Panel shall not be required to so notify the person if the Panel reasonably determines, and the CEO confirms, that such notification will jeopardize the investigation.

5.1.10 Where the Panel has commenced an investigation, the Panel shall:

(a) periodically advise the CEO of the progress of the investigation; and

(b) where the investigation was commenced under section 5.1.1(b), inform the person that filed the complaint or referral of the outcome of the investigation upon being requested in writing to do so by that person.

5.1.11 For the purposes of carrying out an investigation, the Panel has the power to examine and compel the production of any documents or other things, to summon and compel testimony and to enter upon premises and search and seize as authorized by the Electricity Act.

5.1.12 The Panel shall notify the CEO prior to exercising any of the powers referred to in section 5.1.11.

5.1.13 The Panel shall prepare and deliver reports in relation to an investigation in accordance with sections 7.2 and 7.5.

ARTICLE 6
REVIEWS

6.1 Reviews

6.1.1 The Panel may, with the prior concurrence of the CEO, undertake a review of any actual or potential flaws or inefficiencies referred to in section 4.1.1(c) or 4.1.1(d).

6.1.2 The Panel shall prepare and deliver reports in relation to a review in accordance with sections 7.3 and 7.5.

ARTICLE 7
REPORTING

7.1 General Reporting

7.1.1 The Panel shall, not less than semi-annually and more frequently if so requested by the CEO, submit to the CEO written reports on matters pertaining to its responsibilities under this By-law including:

(a) a summary of reports provided to the Panel by the MAU;

(b) a summary of all complaints or referrals filed with the Panel; and

(c) a summary of all investigations or reviews commenced by the Panel.

Once annually, such report shall contain the Panel's general assessment of the state of the IESO-administered markets, including their efficiency and competitiveness.

7.1.2 Where the Panel, in carrying out its responsibilities, identifies that a market participant may be acting contrary to or in non-compliance with statutory authority falling within the jurisdiction of a person, board, agency or tribunal, the Panel shall prepare and submit a written report to that effect to the CEO. The CEO shall thereafter forward the relevant information to the head of the relevant authority.

7.1.3 The Panel shall provide to the CEO such briefings and updates regarding the performance by the Panel of its duties and activities as the CEO may request.

7.2 Report During or Following Investigation

7.2.1 Upon completion of an investigation under Article 5, the Panel shall prepare a written report that sets out, among other information:

(a) the matter that was investigated;

(b) the paragraph of section 5.1.1 under which the investigation was commenced;

(c) the findings of the Panel;

(d) the response of a person under section 7.2.2, if applicable; and

(e) the recommendations of the Panel, if any, and the reasons for such recommendations.

7.2.2 Where the Panel intends to include in a report referred to in section 7.2.1 findings to the effect that a person has engaged in inappropriate or anomalous conduct, the Panel must discuss its findings with the person prior to including such findings in the report. The Panel must also give the person a reasonable opportunity to respond in writing to the allegations. Where the person has not made any response within such reasonable time, the person shall be deemed to have elected to make no response.

7.2.3 A report referred to in section 7.2.1 shall be provided to the CEO, the IESO and any other person that the Panel considers appropriate. Where the Panel intends to provide the report to any such other person, the Panel shall so notify the CEO. The CEO may also provide the report to such persons as the CEO considers appropriate.

7.2.4 A report referred to in section 7.2.1 in respect of an investigation relating to the conduct of a person shall be provided by the CEO to that person unless the CEO, on the advice of the Panel, determines that such disclosure is reasonably likely to compromise the work of the MAU or the Panel. In such a case, the CEO shall provide the person with a redacted version of the report from which any portions that could reasonably compromise the work of the MAU or the Panel have been deleted.

7.2.5 Where the Panel determines that action is urgently required in respect of a matter that is revealed during an investigation, the Panel shall promptly make an interim written report to that effect to the CEO containing the applicable recommendation. Where the urgent action or recommendation that is the subject of the interim report is a matter within the authority or control of the IESO, the Panel shall also provide a copy of the report to the Chief Executive Officer of the IESO. The CEO may provide the report to such persons as the CEO considers appropriate.

7.3 Report Following Review

7.3.1 Upon completion of a review under Article 6, the Panel shall prepare a written report that sets out, among other information:

(a) the matter that was reviewed;

(b) the manner in which the matter came to the attention of the Panel;

(c) the findings of the Panel; and

(d) the recommendations of the Panel, if any, and the reasons for such recommendations.

7.3.2 A report referred to in section 7.3.1 shall be provided to the CEO. The CEO shall provide such report to the IESO and to such other person as the CEO considers appropriate.

7.4 Publication

7.4.1 Subject to section 7.5, all written reports of the Panel shall be posted on the Board's website.

7.5 Confidentiality

7.5.1 Where a written report referred to in this Article contains confidential information obtained by the Panel by compulsory procedures in the course of its duties under this By-law, the Panel shall prepare one or more redacted versions of the report from which the confidential information has

been deleted as may be required to enable the dissemination and publication of the report in accordance with this Article.

7.5.2 Where a written report referred to in this Article contains confidential information obtained by the Panel other than by compulsory procedures in the course of its duties, the Panel shall prepare one or more redacted versions of the report from which the confidential information has been deleted as may be required to enable the dissemination and publication of the report in accordance with this Article.

7.5.3 Sections 7.5.1 and 7.5.2 do not apply in relation to any confidential information that is the subject of an order of the Panel under section 8.2.3.

7.6 Provision of Data

7.6.1 Where the Panel receives a request from a market participant for the provision of data collected or created by the Panel during the course of the monitoring activities referred to in section 4.1.1, the Panel shall so notify the CEO.

7.6.2 The CEO may, provided that the data is not confidential information, authorize the provision of such data unless the CEO, on the advice of the Panel, determines that such provision is reasonably likely to compromise the work of the MAU or the Panel.

7.6.3 A reasonable fee may be charged for the provision of data under section 7.6.2.

ARTICLE 8
CONFIDENTIALITY

8.1 Panel Members

8.1.1 A member of the Panel shall enter into such confidentiality agreement with the Board as the Board of Directors, on the advice of the CEO, determines appropriate.

8.1.2 A member of the Panel shall comply with such protocols as the CEO, considers appropriate regarding the confidentiality and security of records, data handling and communications with Members of the Board and employees of the Board.

8.2 Confidential Information Obtained by Panel

8.2.1 Subject to section 8.2.2, no Member of the Board, employee of the Board or member of the Panel shall communicate or allow access to or

inspection of confidential information that is obtained by the Panel in the course of its duties under this By-law except in the ordinary course of that person's duties.

8.2.2 Except to the extent prohibited by law, confidential information that is obtained by the Panel in the course of its duties may be disclosed:

(a) to the CEO in a report referred to in Article 7 and to the IESO in a report referred to in section 7.2.1, 7.2.5 or 7.3.1;

(b) to the MAU where such disclosure is required to enable the MAU to conduct activities in support of the Panel as described in the Protocol;

(c) to a police force or other investigatory agency or to a regulatory agency;

(d) where required by a summons or direction of the Board;

(e) where the Panel has made an order under section 8.2.3; or

(f) where required by law, judicial order or order of a regulatory body having authority over the matter.

8.2.3 In accordance with section 37.3(3) of the Electricity Act, the Panel shall make an order permitting the disclosure of confidential information obtained by the Panel by compulsory procedures in the course of its duties if, after giving the person from whom the confidential information was obtained and any other person who, in the opinion of the Panel, is an interested party an opportunity to be heard, the Panel is of the opinion that disclosure is in the public interest.

8.2.4 Where the Panel intends to make an order under section 8.2.3, the Panel shall so advise the CEO prior to giving any notice referred to in that section.

8.3 Designated Confidential Information

8.3.1 For the purposes of section 4.3.1(8) of the Act, a record of information that:

(a) relates to a market participant and that was classified as "confidential" by the Independent Electricity Market Operator prior to the date of coming into force of section 4.3.1(1) of the *Act* and included in a market manual prior to that date shall be deemed to

have been designated by the Panel as “confidential” under this By-law; and

(b) relates to a market participant and that was classified as “highly confidential” by the Independent Electricity Market Operator prior to the date of coming into force of section 4.3.1(1) of the Act and included in a market manual prior to that date shall be deemed to have been designated by the Panel as “highly confidential” under this By-law.

8.3.2 The Panel may from time to time designate other records of information relating to a market participant as “confidential” or “highly confidential” for the purposes of section 4.3.1(8) of the Act. Prior to so designating records of information, the Panel shall so notify the CEO.

ARTICLE 9
COMING INTO FORCE

9.1.1 This By-law shall come into force on October 2, 2020. It supersedes and replaces By-law #3 made by the Board effective January 5, 2005.

9.1.2 This By-law shall cease to have effect on the date on which a regulation made under section 4.3.1(9) of the Act comes into force.

Exhibit "M"

OEB and IESO Protocol dated April 25, 2005

Exhibit "M"

to the Affidavit of Francois Tardif

Sworn before me on October 29, 2025, in accordance with O. Reg. 431/20,
Administering Oath or Declaration Remotely



Commissioner for Taking Affidavits
(or as may be)

October 29, 2025

Keith Edward Hickey, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.

Expires June 24, 2027.

Consolidated Version
Amendments made on
April 24, 2008 (section 3.1.2 and Appendix A),
April 25, 2012 (section 6.1.1), October 25, 2013 (sections 2.1.2A, 2.1.2B, 2.2.6 and 6.8.1) and May 1, 2017 (section 6.1.1A)

PROTOCOL
RELATING TO MARKET SURVEILLANCE PANEL

THIS PROTOCOL made as of the 25th day of April, 2005

BETWEEN:

Independent Electricity System Operator, a
corporation continued under the *Electricity Act, 1998*
(the "IESO")

- and -

Ontario Energy Board, a corporation continued
under the *Ontario Energy Board Act, 1998*
(the "OEB")

(each a "Party" and collectively the "Parties")

WHEREAS the Independent Electricity Market Operator had established a Market Surveillance Panel in accordance with the requirements of the *Electricity Act, 1998*;

AND WHEREAS by amendments to the *Ontario Energy Board Act, 1998* the Market Surveillance Panel has been continued as a panel of the OEB effective as of January 1, 2005;

AND WHEREAS the functions, duties and procedures of the Market Surveillance Panel are described in the *Electricity Act, 1998*, the *Ontario Energy Board Act, 1998* and By-law No. 3 of the OEB;

AND WHEREAS the Parties acknowledge that, in order to duly perform its functions and duties, the Market Surveillance Panel will require the on-going support of employees of the IESO;

AND WHEREAS By-law No. 3 of the OEB contemplates that the IESO and the OEB will have a protocol relating to (a) the use by the Market Surveillance Panel of the services of employees of the IESO, including employees forming part of the IESO's market assessment unit, (b) the provision by the Market Surveillance Panel of advice or assistance to the IESO on matters that arise under the market rules, and (c) to such other matters as may be required to give effect to those provisions of the By-law that contemplate the need for a protocol;

AND WHEREAS the Parties wish to enter into this Protocol to give effect to the elements referred to in the preceding paragraph.

NOW THEREFORE this Protocol witnesses that in consideration of the mutual promises and covenants contained in it, the IESO and the OEB agree as follows:

ARTICLE 1
DEFINITIONS AND INTERPRETATION

1.1 Definitions

1.1.1 In this Protocol, unless the context otherwise requires:

"*Act*" means the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Sched. B;

"By-Law" means By-law No. 3 of the OEB;

"confidential information" means information that is not public and that is in its nature confidential, proprietary or commercially sensitive;

"*Electricity Act*" means the *Electricity Act, 1998*, S.O. 1998, c. 15, Sched. A;

"employee" means any person employed by another person, whether on a permanent basis, on a fixed term contract or on secondment, and includes (a) a probationary employee, (b) a temporary employee, and (c) in the case of the OEB, a Crown employee providing services to the OEB under an agreement contemplated in section 4.16(4) of the *Act*, but does not include a Member or a member of the Panel;

"market rules" means the rules made under section 32 of the *Electricity Act*;

"Member" means a member appointed to the OEB by the Lieutenant Governor in Council under the *Act*, and includes the OEB Chair and the Vice-Chairs of the OEB;

"Monitoring Document" has the meaning given to it in section 4.2.1 of the By-law;

"OEB Chair" means the Member designated by the Lieutenant Governor in Council under the *Act* to be the Chair of the OEB;

"Panel" means the Market Surveillance Panel continued as the Market Surveillance Panel of the OEB under the *Act*;

"Panel Chair" means the person appointed by the OEB Chair as the chair of the Panel; and

"Representative" includes a director, officer, employee, partner, agent or independent contractor and includes, in the case of the IESO, a member of a panel established by the IESO.

1.2 Interpretation

1.2.1 Except as provided in section 1.1.1, words and expressions that are defined in the *Act* or the *Electricity Act* have the same meanings when used in this Protocol.

1.2.2 In this Protocol, unless the context otherwise requires:

(a) words importing the singular include the plural and vice versa;

(b) words importing a gender include any gender;

(c) words importing a person include (i) an individual, (ii) a company, sole proprietorship, partnership, trust, joint venture, association, corporation or other private or public body corporate; and (iii) any government, government agency or body, regulatory agency or body or other body politic or collegiate;

(d) a reference to a section or paragraph is to a section or paragraph of this Protocol;

(e) a reference to any statute, regulation, proclamation, order in council, ordinance, by-law, resolution, rule, order or directive includes all statutes, regulations, proclamations, orders in council, ordinances, by-laws, resolutions, rules, orders or directives varying, consolidating, re-enacting, extending or replacing it;

(f) a reference to a document, including a statute, includes an amendment or supplement to, or replacement of, that document, as well as any schedule, appendix or other annexure thereto;

(g) the expression "including" means including without limitation, and the expression "include", "includes" and "included" shall be interpreted accordingly; and

(h) a list of elements preceded by the word "includes", "including", "such as" or similar language shall not be interpreted as excluding any other element, whether of the same or a different nature or scope.

1.2.3. Nothing in this Protocol shall be interpreted as imposing on the IESO an obligation to amend the market rules.

ARTICLE 2
MARKET ASSESSMENT UNIT

2.1 Establishment and Maintenance of Market Assessment Unit

2.1.1. The IESO shall establish and maintain a market assessment unit to, among such other responsibilities as may be assigned to the market assessment unit by the IESO, support the Panel in respect of the Panel's functions, duties and activities as described in the *Electricity Act*, the *Act* and the By-law.

2.1.2. The market assessment unit shall be composed of staff of the IESO with the experience and qualifications necessary to conduct the activities referred to in this Protocol in the manner required and on a timely basis.

2.1.2A Once annually, and more frequently if agreed by the Panel Chair, the Panel Chair shall provide the applicable IESO Representative with an assessment of the performance of members of the market assessment unit in the previous year for the purposes of supporting the IESO's performance management and professional development processes. Such assessment shall be provided at such time and in such manner as may be agreed between the Panel Chair and the IESO Representative.

2.1.2B Once annually, and more frequently if agreed by the Panel Chair, the Panel Chair shall provide the applicable IESO Representative with a 12-month projection of the activities that the Panel plans to undertake and an indication of the resource requirements associated with those activities. Such projection shall be provided in such manner as may be agreed between the Panel Chair and the IESO Representative, and at such time as will enable the projection to be considered as part of the IESO's annual business planning process. The applicable IESO Representative shall provide such supporting information regarding resources as the Panel may reasonably require for planning purposes.

2.1.3. The IESO shall ensure that the market assessment unit has reasonable resources to enable the market assessment unit to conduct the activities referred to in this Protocol in the manner required and on a timely basis.

2.1.4. The IESO shall ensure that the market assessment unit has at all reasonable times the full cooperation of all Representatives of the IESO as may be required to

enable the market assessment unit to conduct the activities referred to in this Protocol in the manner required and on a timely basis.

2.1.5. The IESO shall ensure that the market assessment unit has full access to data in the power, possession or control of the IESO as may be required to enable the market assessment unit to conduct the activities referred to in this Protocol in the manner required and on a timely basis.

2.1.6. Where the OEB Chair considers that:

(a) the level of staffing, resources, data access or IESO cooperation referred to in sections 2.1.2 to 2.1.5 is inadequate for the purposes of enabling the market assessment unit to conduct the activities referred to in this Protocol in the manner required or on a timely basis;

(b) the arrangements made by the IESO to ensure the confidentiality of the market assessment unit's work in support of the Panel, including the protection of files, databases, applications and the establishment of segregated working space, are inadequate; or

(c) the code of conduct or conflict of interest guidelines to which members of the market assessment unit are subject are inadequate having regard to the sensitive nature of the market assessment unit's activities referred to in this Protocol,

the OEB Chair may so notify the Chief Executive Officer of the IESO. The OEB Chair and the Chief Executive Officer of the IESO shall then attempt in good faith to remedy the situation.

2.1.7. The IESO shall provide the OEB Chair with details of the level of staffing, resources, data access, arrangements, code of conduct and conflict of interest guidelines referred to in section 2.1.6 that exist as of the effective date of this Protocol. The IESO shall thereafter notify the Chair of the OEB of any change made to any such matters.

2.1.8. The IESO shall cause each member of the market assessment unit to comply with all of the provisions of this Protocol that apply to the market assessment unit.

2.2 Functions of the Market Assessment Unit

2.2.1. The market assessment unit shall provide such assistance and support as the Panel may require in relation to matters described in Articles 4, 5, 6 and 7 inclusive of the By-law as such By-law read on the effective date of this Protocol. The market assessment unit shall, with the prior concurrence of the Chief Executive Officer of the IESO, provide such assistance and support as the Panel may require in relation

to any matters that may be included in the By-law from time to time after the effective date of this Protocol.

2.2.2. The market assessment unit shall provide reports and briefings to the Panel as may reasonably be required by the Panel.

2.2.3. The market assessment unit shall provide such assistance and support as the Panel may require in relation to activities conducted by the Panel under Article 3.

2.2.4. The market assessment unit shall, with the prior concurrence of the Chief Executive Officer of the IESO, provide such assistance and support as the Panel may require in relation to activities assigned to the Panel by the OEB Chair under section 3.1.7 of the By-law.

2.2.5. The market assessment unit shall, upon request by the Panel:

(a) provide general administrative and clerical support to the Panel as may be reasonably requested by the Panel;

(b) liaise with the IESO and market participants on behalf of the Panel;

(c) attend meetings of the Panel and such other meetings as the Panel may require; and

(d) keep the Panel informed on a timely basis of policy developments in Ontario and elsewhere that are relevant to the functions and duties of the Panel as set out in the By-law.

2.2.6. In relation to the activities referred to in this section 2.2, the market assessment unit shall:

(a) take direction exclusively from the Panel;

(b) be under the exclusive supervision of the Panel; and

(c) except as otherwise provided under section 2.3, report exclusively and directly to the Panel.

Such exclusive direction, supervision and reporting shall extend to all matters pertaining to the conduct of the activities referred to in this section 2.2, but shall not be construed as limiting the ability of the IESO to direct, supervise or receive reports in relation to other responsibilities assigned to the market assessment unit as contemplated in section 2.1.1 or to address administrative or human resource matters pertaining to the employment of the members of the market assessment unit.

2.3. Access to Information, Segregation and Confidentiality

2.3.1. The market assessment unit:

(a) shall not, without the prior concurrence of the Panel, discuss its work in relation to investigations referred to in Article 5 of the By-law with any Representative of the IESO or of a market participant;

(b) shall not, without the prior concurrence of the Panel, provide copies of any reports or other documents that it prepares in relation to the activities referred to in section 2.2 to any Representative of the IESO or of a market participant;

(c) shall not, without the prior concurrence of the Panel, disclose any confidential information provided to it by the Panel to any person or use any such confidential information for any purpose other than the purpose for which it was so provided; and

(d) shall, upon request by the Panel, return to the Panel any confidential information provided to the market assessment unit by the Panel, with no copy or portion kept by the market assessment unit.

2.3.2. The market assessment unit shall, at the request of the Panel but only to the extent required by the Panel, provide to such persons as may be designated by the Panel excerpts of a draft document for the purpose of enabling such persons to confirm the factual accuracy of, or to otherwise comment on, the draft document.

2.3.3. The market assessment unit shall comply with all provisions of the market rules pertaining to the protection and non-disclosure of confidential information in relation to confidential information obtained by it from or in respect of a market participant.

2.3.4. The IESO shall ensure that electronic and paper files pertaining to the activities of the market assessment unit referred to in section 2.2 are secure from access by anyone other than the members of the market assessment unit and the members of the Panel. Nothing in this section 2.3.4 shall be construed to prohibit designated staff of the IESO from providing technical IT support to the market assessment unit.

ARTICLE 3
PANEL ASSISTANCE TO THE IESO

3.1. Scope of Assistance

3.1.1. The IESO may request that the Panel provide it with assistance and advice on matters that arise under the market rules and that are within the Panel's area of expertise. The Panel shall, with the prior concurrence of the OEB Chair, provide such assistance and advice.

3.1.2. Subject to sections 3.1.3 and 3.1.4, the Panel is hereby authorized by the OEB Chair to provide, and shall upon request provide, assistance and advice to the IESO on the following matters:

(a) the approval by the IESO of the aggregation of facilities as referred to in section 2.3.2.3 of Chapter 7 of the market rules as they read on December 1, 2004;

(b) changes or revisions to dispatch data by a market participant as referred to in section 3.3.6 of Chapter 7 of the market rules as they read on April 1, 2008;

(c) changes or revisions to dispatch data by a market participant as referred to in section 3.3.8 of Chapter 7 of the market rules as they read on December 1, 2004;

(d) the failure by a registered market participant to comply with dispatch instructions as referred to in section 7.5.7 of Chapter 7 of the market rules as they read on December 1, 2004;

(e) confirmation that the IESO has obtained contracted ancillary services or reliability must-run contracts in the presence of market power as referred to in section 9.8.1.4 of Chapter 7 of the market rules as they read on December 1, 2004; and

(f) the establishment of the methodology for determining elements of a reference price relating to local market power as referred to in section 1.3.5 of Appendix 7.6 of Chapter 7 of the market rules as they read on December 1, 2004.

For convenience of reference, the sections of the market rules referred to in this section 3.1.2 as they read on the relevant date referred to above are reproduced in Appendix A.

3.1.3. Where the IESO wishes the Panel to commence an investigation or a review in relation to any of the matters referred to in section 3.1.2, the IESO shall refer the

matter to the Panel and the matter shall be dealt with by the Panel in accordance with Article 5 or Article 6 of the By-law, as applicable.

3.1.4. The OEB Chair may, on sixty days' notice to the Chief Executive Officer of the IESO, revoke the authorization of the Panel to assist or advise the IESO on one or more of the matters referred to in section 3.1.2 where the OEB Chair, on the advice of the Panel, considers that:

(a) the provision of such assistance or advice is having an adverse effect on the ability of the Panel to perform its other functions, duties and activities;

(b) the provision of such assistance or advice is no longer within the Panel's area of expertise; or

(c) the provision of such assistance or advice by the Panel is not adequately supported by the market assessment unit.

3.1.5. The Panel is authorized to, and shall upon request, brief the IESO Board on the periodic monitoring reports it has published in respect of the IESO-administered markets.

ARTICLE 4
ADDITIONAL RIGHTS AND OBLIGATIONS

4.1. Exchange of Information

4.1.1. The IESO shall provide or make available to the Panel such information as the Panel may require to enable the Panel to perform its functions, duties and activities as set out in the *Electricity Act,* the *Act* or the By-law. Without limiting the generality of the foregoing, the market assessment unit shall provide or make available to the Panel data that is identified in the Monitoring Documents and that is required to be provided to the market assessment unit under the market rules.

4.1.2. The IESO shall ensure that the Panel has access at all reasonable times to the electronic and paper files pertaining to the activities of the market assessment unit referred to in section 2.2.

4.1.3. A Party shall provide to the other Party any information that comes to its attention and that pertains to:

(a) developments or events that are relevant to the functions, duties and activities of the Panel as set out in the *Electricity Act,* the *Act* or the By-law or to the activities of the market assessment unit as set out in section 2.2;

(b) concerns expressed about the work of the market assessment unit or of the Panel; or

(c) a request by a third party for access to or the disclosure of confidential information obtained or developed by:

i. the market assessment unit in conducting the activities referred to in section 2.2; or

ii. the Panel in performing the functions, duties and activities referred to in section 4.1.3(a).

4.1.4. Without limiting the generality of section 4.1.3, the IESO shall promptly notify the Panel of any proposed amendment to the IESO's information confidentiality catalogue referred to in the market rules.

4.2. Consultations

4.2.1. The OEB Chair and the Chief Executive Officer of the IESO shall consult with one another from time to time as may be required in relation to the matters referred to in this Protocol.

4.2.2. Without limiting the generality of section 4.2.1, the OEB Chair and the Chief Executive Officer of the IESO shall consult one another in the event that either person has concerns regarding this Protocol or its implementation by a Party. The OEB Chair and the Chief Executive Officer shall attempt in good faith to resolve any inadequacies, deficiencies or difficulties in relation to the terms of this Protocol or its implementation.

4.3. Costs and Expenses

4.3.1. Subject to section 4.3.2, each Party shall bear its own costs of implementing and complying with the provisions of this Protocol.

4.3.2. Where the IESO incurs out-of-pocket expenses in relation to the conduct of the activities referred to in section 2.2.5, these expenses shall be reimbursed by the OEB provided that they are reasonable and that the IESO provides the OEB with an invoice supported by receipts. For greater certainty, "out-of-pocket expenses" shall not include any salary or other remuneration paid to members of the market assessment unit by the IESO.

4.3.3. Unless otherwise instructed to do so by the OEB, the IESO shall not include federal Goods and Services Tax in any invoice submitted to the OEB under this Protocol.

4.3.4. Where the OEB incurs out-of-pocket expenses in relation to the conduct by the Panel of the activities referred to in Article 3, these expenses shall be reimbursed by the IESO provided that they are reasonable and that the OEB provides the IESO with an invoice supported by receipts. For greater certainty, "out-of-pocket expenses" shall not include any remuneration paid to members of the Panel by the OEB.

4.4. Intellectual Property

4.4.1. The OEB shall be the sole owner of any copyright associated with or contained in any reports or other documentation prepared by the market assessment unit in the conduct of the activities referred to in section 2.2, as well as all rights and interests ancillary thereto.

4.4.2. Subject to section 4.4.3, the IESO shall, in order to give effect to section 4.4.1:

(a) obtain waivers of all rights of integrity and any other moral rights in relation to the reports or other documentation prepared by the market assessment unit in the conduct of the activities referred to in section 2.2 from any person in the position to assert such rights, which waivers may be invoked without restriction by any person authorized by the OEB to use such reports or other documentation;

(b) ensure that nothing provided by the market assessment unit to the Panel infringes upon or violates any third party intellectual property rights;

(c) from time to time at the request of the OEB, execute and cause to be executed by any applicable person a written assignment of copyright, a waiver of all moral rights and such other document as may be reasonably required by the OEB to in order to give effect to sections 4.4.1 and 4.4.2(a); and

(d) from time to time assist the OEB in preparing any applicable Canadian intellectual property registration.

4.4.3. The IESO shall not be required to comply with its obligations under section 4.4.2(a) or 4.4.2(c) if and to the extent that such matters have been addressed directly between the OEB and the member of the market assessment unit or other applicable person.

ARTICLE 5
REPRESENTATIONS AND WARRANTIES

5.1. Representations and Warranties of IESO

5.1.1. The IESO hereby represents and warrants as follows to the OEB and acknowledges and confirms that the OEB is relying on such representations and warranties without independent inquiry in entering into this Protocol:

(a) it is a corporation duly continued and existing under the laws of the Province of Ontario;

(b) it has all the necessary corporate power to enter into and perform its obligations under this Protocol;

(c) the execution, delivery and performance of this Protocol by it has been authorized by all necessary corporate and/or governmental action and does not (or would not with the giving of notice, the lapse of time or the happening of any other event or condition) result in a violation or a breach of or a default under, or give rise to a right of termination, greater rights or increased costs, amendment or cancellation or the acceleration of any obligation under (i) any charter or by-law instruments of the IESO; (ii) any contracts or instruments to which the IESO is bound; or (iii) any laws applicable to it;

(d) each individual executing this Protocol, and any document in connection herewith, on behalf of the IESO, has been duly authorized to execute this Protocol and has the full power and authority to bind the IESO; and

(e) this Protocol constitutes a legal and binding obligation on the IESO, enforceable against the IESO in accordance with its terms.

5.1.2. The IESO shall promptly notify the OEB of any circumstance that does or may result in any of the representations and warranties set forth in section 5.1.1 becoming untrue or inaccurate during the term of this Protocol.

5.2. Representations and Warranties of OEB

5.2.1. The OEB hereby represents and warrants as follows to the IESO and acknowledges and confirms that the IESO is relying on such representations and warranties without independent inquiry in entering into this Protocol:

(a) it is a corporation duly continued and existing under the laws of the Province of Ontario;

(b) it has all the necessary corporate power to enter into and perform its obligations under this Protocol;

(c) the execution, delivery and performance of this Protocol by it has been authorized by all necessary corporate and/or governmental action and does not (or would not with the giving of notice, the lapse of time or the happening of any other event or condition) result in a violation or a breach of or a default under, or give rise to a right of termination, greater rights or increased costs, amendment or cancellation or the acceleration of any obligation under (i) any charter or by-law instruments of the OEB; (ii) any contracts or instruments to which the OEB is bound; or (iii) any laws applicable to it;

(d) each individual executing this Protocol, and any document in connection herewith, on behalf of the OEB, has been duly authorized to execute this Protocol and has the full power and authority to bind the OEB;

(e) this Protocol constitutes a legal and binding obligation on the OEB, enforceable against the OEB in accordance with its terms; and

(f) the OEB is exempt from the application of the federal Goods and Services Tax in relation to any services that may be provided by the IESO under this Protocol.

5.2.2. The OEB shall promptly notify the IESO of any circumstance that does or may result in any of the representations and warranties set forth in section 5.2.1 becoming untrue or inaccurate during the term of this Protocol.

ARTICLE 6
GENERAL

6.1. Term and Termination

6.1.1. This Protocol shall come into force on the date first written above and shall remain in effect for a period of one year from that date, and may thereafter be renewed by the parties for such additional terms of one year or more as the parties may agree. Despite the foregoing, the parties may from time to time agree to a renewal term of less than one year where special circumstances so warrant.

6.1.1A Despite section 6.1.1, as of May 1, 2017 this Protocol shall be automatically renewed for successive two-year terms unless either Party gives notice to the other at least 120 days prior to the expiration of any renewal term of the Party's intention not to renew.

6.1.2. This Protocol shall expire on the date on which a regulation made under section 4.3.1(9) of the *Act* comes into force.

6.2. Amendments

6.2.1. No amendment of this Protocol shall be effective unless made in writing and signed by the Parties.

6.3. Assignment

6.3.1. No Party may assign or transfer, whether absolutely, by way of security or otherwise, all or any part of its rights or obligations under this Protocol without the prior written consent of the other Party.

6.4. Successors and Assigns

6.4.1. This Protocol shall enure to the benefit of, and be binding on, the Parties and their respective successors and permitted assigns.

6.5. Further Assurances

6.5.1. Each Party shall promptly execute and deliver or cause to be executed and delivered all further documents in connection with this Protocol that the other Party may reasonably require for the purposes of giving effect to this Protocol.

6.6. Waiver

6.6.1. A waiver of any default, breach or non-compliance under this Protocol is not effective unless in writing and signed by the Party to be bound by the waiver. No waiver will be inferred or implied by any failure to act or by the delay in acting by a Party in respect of any default, breach or non-observance or by anything done or omitted to be done by the other Party. The waiver by a Party of any default, breach or non-compliance under this Protocol shall not operate as a waiver of that Party's rights under this Protocol in respect of any continuing or subsequent default, breach or non-observance (whether of the same or any other nature).

6.7. Severability

6.7.1. Any provision of this Protocol that is determined by a court of competent jurisdiction to be invalid or unenforceable shall be ineffective to the extent of that invalidity or unenforceability and shall be deemed severed from the remainder of this Protocol, all without affecting the validity or enforceability of the remaining provisions of this Protocol.

6.8. Notices

6.8.1. Any notice, demand, consent, request or other communication required or permitted to be given or made under this Protocol shall be validly and effectively made or given if made or given in writing and delivered by first class mail, postage prepaid, by facsimile transmission or by personal delivery, and addressed to the Party to whom it is intended at its address as set out below:

(a) if to the OEB, addressed to the attention of the OEB Chair or the Panel Chair, as the case may be, at:

Ontario Energy Board
2300 Yonge Street, 27th Floor
P.O. Box 2319
Toronto, ON M4P 1E4

Facsimile No.: 416-440-7656

(b) if to the IESO, addressed to the attention of the Director, Market Assessment and Compliance or the Chief Executive Officer of the IESO, as the case may be, at:

Chief Executive Officer
Independent Electricity System Operator
Station A, Box 4474
Toronto, ON M5W 4E5

Facsimile No.: 416-506-2849

Director, Market Assessment and Compliance
Independent Electricity System Operator
Station A, Box 4474
Toronto, ON M5W 4E5

Facsimile No.: 905-855-6408

A Party may change its address by written notice to the other Party given as aforesaid. Such change shall not constitute an amendment to this Protocol for the purposes of the application of section 6.2.1.

6.8.2. A notice, demand, consent, request or other communication shall be treated as having been duly given or made to a person by the sender:

(a) where given or made by first class mail, on the fourth business day after the date of mailing;

(b) where given or made by facsimile transmission, on the day and at the time of transmission as indicated on the sender's facsimile transmission report, if a business day or, if the transmission is on a day which is not a business day or is after 5:00 pm, at 9:00 am on the following business day; or

(c) where given or made by personal delivery, when the person actually receives the notice, demand, consent, request or other communication.

6.9. Governing Law

6.9.1 This Protocol shall be governed by and interpreted in all respects in accordance with the laws of the Province of Ontario and the federal laws of Canada applicable therein.

6.10. Counterparts

6.10.1. This Protocol may be executed in one or more counterparts which, together, shall constitute one and the same Protocol. This Protocol shall not be binding until it has been executed by each of the Parties and delivered to each of the Parties.

IN WITNESS WHEREOF the Parties have, by their duly appointed and authorized representatives, executed this Protocol.

Independent Electricity System Operator	**Ontario Energy Board**
By:	By:
Name: David Goulding	Name: Howard Wetston, Q.C.
Title: Chief Executive Officer	Title: Chair

Appendix A

Excerpt from Market Rules
(section 3.1.2)

1. Section 2.3.2.3 of Chapter 7

2.3.2 The *IMO* shall approve an application for the aggregation of *facilities* into a single *registered facility* unless:

(…)

2.3.2.3 one or more of the facilities proposed to be aggregated is or includes *generating* unit or a *load facility*:

(…)

c. whose *offer* or *bid* information or whose in service or out of service status is information required to be submitted to the *market assessment unit* or the *market surveillance panel* in furtherance of their respective functions and obligations under the *Electricity Act, 1998* and these *market rules*; or

(…)

2. Section 3.3.6 of Chapter 7

3.3.6 Where pursuant to section 3.3.5, the approval of the *IESO* is required for the submission of revised *dispatch data*, the *IESO* shall, unless the change in quantity poses risks in relation to the *reliability* or *security* of the *electricity system*, approve the submission of revised *dispatch data* where:

(…)

3.3.6.3 the *registered market participant* indicates, at the time of the submission of the revised *dispatch data*, that the revision is required in order to reflect a proposed change in the operational status of the *registered facility* designed solely to prevent the *registered facility* from operating in a manner that would violate any *applicable law*, endanger the safety of any person or damage property or the environment.

The *IESO* may refer such changes or revisions of *dispatch data* to the *market surveillance panel.*

3. Section 3.3.8 of Chapter 7

3.3.8 Notwithstanding any other provision of this section 3.3, a *registered market participant* shall as soon as practicable submit to the *IMO* revised *dispatch data* for any *registered facility* in respect of which it is the *registered market participant* if, for any *dispatch hour* in the current *pre-dispatch schedule*, the quantity of any *physical service* scheduled for that *registered facility* differs from the quantity the *registered market participant* reasonably expects to be delivered or withdrawn by more than the greater of (i) 2 percent (ii) such absolute amount as may be determined by the *IMO* based on considerations of *reliability* and *facility* specific characteristics, (iii) in the case of a *cogeneration facility* that is either a *dispatchable* or *self-scheduling generation facility*, such amount based on the impact that the production of the other forms of useful energy within the *facility* has on *energy* production based on the information outlined in section 2.2.6.10, and the *IMO*, and (iv) in the case of an *enhanced combined cycle facility* that is either a *dispatchable* or *self-scheduling generation facility*, such amount based on the impact that the recovery of waste heat from an industrial process/processes within the *facility* has on *energy* production based on the information outlined in section 2.2.6.10, and the *IMO*:

a. shall, unless the change in quantity poses risks in relation to the *reliability* or *security* of the *electricity system*, include such change as an input in respect of any subsequent *market schedules* determined following receipt of the change; and

b. may refer such changes or revision of *dispatch data* to the *market surveillance panel*.

4. Section 7.5.7 of Chapter 7

7.5.7 Until the *registered market participant* for a non-conforming *registered facility* responds to the requirements of this section 7.5 to the satisfaction of the *IMO*, such *registered facility* shall continue to be designated as non-conforming, and such failure to respond on the part of that *registered market participant* may be referred by the *IMO* to the *market surveillance panel* at any time.

5. Section 9.8.1.4 of Chapter 7

9.8.1 The *IMO* shall treat information relating to the procurement of *contracted ancillary services* and *reliability must-run contracts* as follows:

(…)

9.8.1.4 where the *IMO* obtains *contracted ancillary services* or *reliability must-run contracts* in the presence of market power, as confirmed by the *market surveillance panel*, the *IMO* shall *publish* the relevant terms and

conditions of the contracts, except for the price which shall not be disclosed, in order to encourage competition.

6. Section 1.3.5 of Appendix 7.6 of Chapter 6

1.3.5 The *market surveillance panel* shall, for the purposes of section 1.3.2 and in accordance with sections 1.3.6 and 1.3.7, establish the methodology for determining a pair of high end factors and a pair of low end factors for each type of *reference price* referred to in section 1.3.3, including the alternative *reference price* referred to in section 1.3.3.1B, if any. Such methodology shall:

1.3.5.1 be submitted to the *IMO Board* for approval; and

1.3.5.2 be *published* by the *IMO* in the form approved by the *IMO Board.*

Exhibit "N"

OEB Market Surveillance Panel report dated August 2025

Exhibit "N"

to the Affidavit of Francois Tardif

Sworn before me on October 29, 2025, in accordance with O. Reg. 431/20, Administering Oath or Declaration Remotely



Commissioner for Taking Affidavits
(or as may be)

October 29, 2025

Keith Edward Hickey, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.

Expires June 24, 2027.

A1767

ONTARIO ENERGY BOARD

The Market Surveillance Panel

The Market Surveillance Panel in the Renewed IESO-Administered Markets

August 2025

Ontario Energy Board

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1 INTRODUCTION

This report informs market participants and other interested parties about Ontario's Market Surveillance Panel (MSP) and its mandate to monitor, investigate, review and report on activities related to the IESO-administered markets, with a focus on market participant conduct and the efficiency and competitiveness of Ontario's wholesale electricity market. The report explains how the MSP will continue to perform its mandate within the Independent Electricity System Operator's (IESO) renewed markets.[1]

The MSP is a statute-based panel of the Ontario Energy Board (OEB). It serves as the market monitor for the Ontario wholesale electricity markets, which are administered by the IESO. The MSP's mandate is set out in the *Electricity Act, 1998*, and the OEB's By-law #2. The work of the MSP is supported by the Market Assessment Unit (MAU) within the IESO, in accordance with a Protocol between the IESO and the OEB.

The renewed markets were launched on May 1, 2025, as part of the IESO's Market Renewal Program (MRP). The IESO expects that "MRP will deliver a more efficient, stable marketplace with competitive and transparent mechanisms that meet system and participant needs at lowest cost."[2] To deliver on its stated mission, MRP replaces the two-schedule market with a single-schedule market, introduces a day-ahead market and implements an enhanced real-time unit commitment program. In addition, the IESO has introduced a new market power mitigation framework to address the potential for suppliers to exercise market power in the energy and reserve markets.

Over the past two decades, the MSP has recorded the findings of its activities in reports published by the OEB. These reports have frequently included recommendations to the IESO to address:[3]

[1] This report provides an overview of the MSP and its mandate with reference to the renewed markets. As such, this report is not a monitoring document as described under Bylaw #2, Article 4.2.1. The MSP may issue new or revised monitoring documents in the future and is reviewing all previous monitoring documents issued under the legacy market to assess their applicability to the renewed markets.
[2] The IESO website provides a description of the components of MRP and the program's objectives. The IESO's objectives for the MRP are described similarly in numerous public reports accessible on the IESO website.
[3] The MSP has occasionally made recommendations to government, the OEB and the former Ontario Power Authority.

- Flaws in the market rules, market design and the overall market structure, which result in outcomes that are inconsistent with the efficient and fair operation of a competitive market
- Inappropriate conduct by market participants
- IESO activities and procedures that adversely impact efficiency or effective competition.

In several cases, the MSP's reports have influenced IESO decisions to amend the market rules, or to modify its activities or the market design for the purpose of improving market efficiency and promoting effective competition.[4] In some instances, the MSP's reports have informed activity by the IESO's market rule enforcement body, the Market Assessment and Compliance Division (MACD), sometimes resulting in remedial actions, settlement repayments or financial penalties.[5] The IESO has frequently cited the MSP's reports in support of the need for MRP.[6]

The MSP's mandate does not change with the implementation of the renewed markets – the MSP will continue to assess and report on the IESO-administered markets and the conduct of market participants. However, the complexities of the renewed markets have increased relative to the legacy markets. In preparation for the renewed markets, the MSP has developed new tools and indicia.

The purpose of this report is to offer interested parties insights into the on-going role of the MSP and its mandate, and to explain how the MSP intends to monitor the renewed IESO-administered markets. As the renewed markets operate and evolve, so too will the MSP's approach to market monitoring.

The remainder of this report is organized as follows:

- Section 2 describes the purpose of market surveillance in deregulated, competitive wholesale electricity markets, and the role

[4] See Appendix 1 for select examples of past MSP report findings and recommendations.
[5] This includes the MSP's Report on an Investigation into Goreway Station Partnership and Report on an Investigation into Possible Gaming Behaviour Related to Congestion Management Settlement Credit Payments by Abitibi-Consolidated Company of Canada and Bowater Canadian Forest Products Inc.
[6] References to various MSP reports can be found in the IESO's two business case studies on the benefits of MRP: The Future of Ontario's Electricity Market: A Benefits Case Assessment of the Market Renewal Project, The Brattle Group, 2017, and Market Renewal Program: Energy Stream Business Case, IESO, 2019, and in other MRP supporting documentation.

and responsibilities of the MSP in Ontario's electricity sector, including its structure and its mandate to monitor, investigate, review and report on the IESO-administered markets. This includes a discussion of monitoring indicia and tools used under the legacy markets, some of which will remain relevant under the renewed markets.

- Section 3 discusses the changes made to the markets under MRP and key aspects of the MSP's approach for monitoring the renewed markets.
- Section 4 offers summary remarks.

.

2 THE ROLE AND RESPONSIBILITIES OF THE MARKET SURVEILLANCE PANEL

2.1 The Purpose of Market Surveillance in Competitive Electricity Markets

A specialized surveillance function is common to all jurisdictions with competitive wholesale electricity markets. The consistent presence of this function reflects the unique features of electricity as a product, the elaborate rules and regulations governing the operation of the electrical system and markets, and the potential for harm to consumers and competition from inappropriate or anti-competitive conduct.[7] The surveillance function is performed by an entity commonly referred to as "the market monitor." The market monitor is tasked with conducting day-to-day monitoring of the markets and with reviewing and investigating anomalous market outcomes and conduct as well as potential flaws in market design or structure. The market monitor also reports to the appropriate regulator or governing authorities instances where the markets are not performing according to their stated objectives, with a typical focus on the objectives of effective competition and efficiency.[8]

The organizational structure of the market monitor varies across jurisdictions. Some are managed within the system operator, some are managed externally by third parties, while others are a hybrid model of both an internal and external monitor. The MSP is an external monitor (appointed by the OEB), that is supported by staff within the MAU who are employed by the IESO. Regardless of structure, all market monitors are designed to perform their responsibilities independent of the influence of market participants and the system operator.[9]

[7] Gaming of Electricity Markets — The Ontario Experience, N. Campbell, Energy Regulation Quarterly, July 2014 – Volume 2, Spring 2014. It is the special features of electricity markets that set them apart from most markets that are subject only to general oversight by competition law authorities.
[8] Market Monitoring Units in Regional Transmission Organizations and Independent System Operators, 111 FERC ¶ 61,267 (2005) at page 1 for a description of the purpose and role of market monitors in the United States.
[9] Wholesale Competition in Regions With Organized Electric Markets; Proposed Rules, 125 FERC ¶ 61,071 (2008) page 171.

Market monitors are typically not enforcement agencies, compliance officers or regulators.[10] They do not have powers to take remedial action or impose sanctions on market participants or the system operator. Instead, market monitors are independent agencies that specialize in the study of firm behaviour, market dynamics and performance, and are best able to analyze market data and to propose potential remedies generally focused on market efficiency and competition for consideration by the appropriate regulatory or governing authorities.

Competitive wholesale markets for electricity were introduced, at least in part, to harness the forces of competition, which in turn leads to economic efficiency by encouraging firms to be more productive and innovative. Market monitoring plays an important role in improving the efficiency, integrity and transparency of competitive wholesale markets. As independent specialists, market monitors expose instances where the market design or structure, system operator's activities or conduct of market participants does not align with the goals of competition and economic efficiency, and propose remedial action to regulatory and other governing authorities.[11]

2.2 The Structure of Ontario's Market Monitor

The MSP was established by the Board of Directors of the Independent Electricity Market Operator (now IESO), as required under the *Electricity Act, 1998*, in preparation for the opening of Ontario's wholesale market in 2002. The MSP was transferred to the OEB pursuant to the *Electricity Restructuring Act, 2004*.

[10] Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorizations, 105 FERC ¶ 61,218 (2003) (Market Behaviour Rules Order), paragraph 1, Appendix A, where FERC clarified that the role of enforcement was its responsibility and that market monitors were to refer all potential compliance issues to it. In Ontario, the responsibility for market rule enforcement rests with the IESO's MACD, which has executed this role since market opening. The OEB also has the power to take remedial action or impose sanctions for non-compliance with the market rules. Alberta's Market Surveillance Administrator does perform the dual role of market monitoring and enforcement to a limited extent but, in this regard, it is distinct from the MSP and market monitors in the United States.

[11] Both the system operator and the market monitor share responsibility for the objectives of competition and economic efficiency. An important benefit of the sharing of responsibility is the focus placed by the market monitor on the impact on economic efficiency of the market design, rules, system operator programs and procedures, which otherwise tends to be subordinated to operational and reliability considerations, which are core responsibilities of the system operator.

The MSP consists of at least three qualified members appointed for fixed terms by the OEB, with one member being appointed as the MSP Chair. MSP members may not have a material interest in a market participant or be a director, officer, employee or agent of, among others, a market participant, the IESO or an affiliate of a market participant or the IESO.[12] A quorum for every meeting of the MSP consists of a majority of members, with a decision on a question facing the MSP requiring a majority of the votes cast on the question.

The MSP is assisted in its functions by the MAU, a ring-fenced division within the IESO's MACD. Upon the transfer of the MSP to the OEB, it was recognized that the MSP would continue to need the support of a full-time team of analysts to conduct day-to-day monitoring and other tasks under the direction of the MSP. Accordingly, the legislation contemplates that the MSP may use the services of IESO employees[13] and the Protocol between the IESO and the OEB governs this relationship. Under the terms of the Protocol, the MAU takes direction exclusively from the MSP in relation to matters falling within the MSP's mandate. The MAU is staffed with economists, engineers and market specialists who report within the IESO to the Vice-President of MACD on administrative matters. The MSP also receives legal and communications support from employees of the OEB.

2.3 The MSP's Mandate

The MSP's specific responsibilities are set out in By-law #2 and include:

- Monitoring, evaluating and analyzing activities related to the IESO-administered markets and market participant conduct (Article 4)
- Investigating activities related to the IESO-administered markets or market participant conduct (Article 5)
- Reviewing actual or potential flaws or inefficiencies identified as a result of its monitoring activities (Article 6)
- Reporting on the above activities, including reporting at least semi-annually (or as requested by the Chief Executive Officer (CEO) of the

[12] The restrictions are set out in Section 4.3.1(3) of the *Ontario Energy Board Act, 1998*, and section 2.1.4 of By-law #2.
[13] Section 4.3.1 (5) of the *Ontario Energy Board Act, 1998*.

OEB) on matters pertaining to its responsibilities and once annually on the MSP's general assessment of the state of the IESO-administered markets, including their efficiency and competitiveness (Article 7).

The MSP's mandate does not extend to an evaluation of the merits of government directives and policies in the abstract. To the extent that the MSP studies and reports on government policy, it is to contextualize its effects on the efficiency and competitiveness of the IESO-administered markets.

The following offers further information on how the MSP performs its responsibilities, all of which with the support of the MAU.

2.4 Monitoring

The MSP monitors the IESO-administered markets and market participant conduct for the following:

- Inappropriate or anomalous market conduct, including gaming or abuses of market power
- Activities of the IESO that have a detrimental impact on market efficiency or effective competition
- Flaws in the market rules, market design, procedures and the overall market structure, which result in outcomes that are inconsistent with the efficient and fair operation of a competitive market.

The MSP reports on its monitoring activities and provides an annual assessment of the state of the IESO-administered markets, which it now does through its annual *State of the Market* reports. The two *State of the Market* reports, and the 37 monitoring reports that preceded them, are available on the OEB's website. These reports are submitted to the CEO of the OEB, who in turn shares the report with the CEO of the IESO together with a request that the IESO advise on the actions it plans to take in response to any MSP recommendations contained in the report.[14] The MSP recommends remedial actions to mitigate conduct, flaws and inefficiencies

[14] As a condition of its licence, the IESO is also required to make an annual filing to the OEB with the status of actions taken by the IESO in response to outstanding MSP recommendations and, where no action has been taken, the rationale for not taking action. These annual filings are available on the IESO website.

identified through its monitoring activities, for the consideration of the OEB and the IESO.

As stated above and pursuant to By-law #2 and the Protocol, the MSP is responsible for monitoring, but from an operational perspective, the MAU supports the MSP and carries the primary responsibility for the day-to-day assessment of market data, IESO activities and market participant conduct. To do this, the MAU is expected to have the relevant in-depth expertise and to employ a wide range of analytic tools, models and performance metrics that support the MSP's monitoring requirements.

A key focus of the MAU is to identify, understand and explain market outcomes or conduct that they believe is potentially anomalous. The MSP defines anomalous to be market outcomes or market participant conduct that is inconsistent with expectations (particularly of a competitive and efficient market) or that falls outside of predicted patterns, trends or norms.

What the MSP considers as anomalous has evolved over time, as the markets have evolved and the understanding of the markets has grown. Through its work with the MSP and the ongoing assessment of the market, the MAU has and will continue to develop a keener understanding of the crucial factors influencing market outcomes. This understanding is a critical skill set when it comes to the measure of support that the MAU provides to the MSP.

The MAU reports to the MSP on their assessment activities and the identification of potentially anomalous market conduct or outcomes, at least monthly and more frequently as required. A summary of the key monitoring metrics used in the evaluation of anomalous market outcomes and market conduct under the legacy market design is provided below.

By-law #2 requires the MSP to monitor for inappropriate conduct, including gaming and abuses of market power.

The MSP defines gaming[15] as conduct involving four elements:

- A defect or gap in the market design, rules or procedures governing the IESO-administered markets (market defect)
- Exploitation of the market defect by a market participant
- Profit or benefit to the participant
- Expense or disadvantage to the market.[16]

A key evidentiary consideration in gaming is the economic intent for the conduct.[17] Conduct that is clearly inconsistent with efficient market behaviour or motivated by profit opportunities that are inconsistent with the economic fundamentals of supply and demand are indicia of possible manipulative gaming activity.

Market power, the exercise of market power, and the abuse of market power are standard concepts in the fields of economics and competition law.

Market power is the ability of a firm (or a group of firms) to restrict output to profitably raise and maintain prices above competitive price levels.[18] A firm may possess market power by virtue of its size, location, a unique cost or product advantage, or the presence of barriers to entry by competitors. A firm exercises market power when it acts on its ability by restricting output, thereby increasing market prices.

An abuse of market power entails an action (anti-competitive act) on the part of a firm (or a group of firms) that aims to impede or lessen the competitive response of one or more rival firms. Impeding or lessening the competitive

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[15] By way of comparison, the Federal Energy Regulatory Commission has defined gaming to include "behavior that circumvents or takes unfair advantage of market rules or conditions in a deceptive manner that harms the proper functioning of the market and potentially other market participants or consumers." See Staff White Paper on Anti-Market Manipulation Enforcement Efforts Ten Years After EPACT 2005, page 23.

[16] See the MSP's Monitoring Document: Monitoring of Offers and Bids in the IESO-Administered Electricity Markets (March 2010), page 44.

[17] The MSP has noted that "an essential element of gaming related to a Market Defect is the exploitation of the opportunity" and that the MSP "considers that exploitation may exist where the market participant had some level of intention to exploit or knowledge of an opportunity to exploit arising from the Market Defect." See Report on an Investigation into Possible Gaming Behaviour Related to Infeasible Import Transactions Offered by West Oaks NY/NE, LP on the Manitoba-Ontario Intertie (Oct 2012) page 19.

[18] The competitive price level is the price that would prevail in equilibrium in an idealized perfectly competitive market. Under perfect competition, the price at which the market clears is equal to the short-run marginal cost of the marginal supplier and is at least as great as the marginal supplier's average variable cost.

response increases or preserves the ability of the firm(s) to exercise market power. Exclusionary practices, collusion (bid rigging, price fixing, agreements to withhold capacity, etc.) and predatory pricing (pricing below marginal cost to drive out or discipline competition) are classic examples of anti-competitive activity that could constitute an abuse of market power if engaged in by a firm (or multiple firms) that has (or collectively have) market power.

Possessing or exercising market power itself is not objectionable under Canadian competition law.[19] For example, market power obtained because of a superior product, business acumen or historic accident, is not, by itself, objectionable. However, abusing market power to substantially lessen competition is objectionable.

In the context of the IESO-administered markets, the MSP monitors for both the exercise of market power and the abuse of market power. Its approach to the exercise or abuse of market power is informed by the fields of economics and Canadian competition law.

A market participant may possess market power by virtue of its share of generation capacity, its location on a congested transmission grid, or its cost structure and relative positioning on the energy offer curve. A market participant that possesses market power may exercise this power in two ways:

- Economic withholding:[20] This is defined as a decision by a market participant to offer generation capacity into the market but at a price that exceeds the short-run marginal cost of the capacity and exceeds the market clearing price.
- Physical withholding: This is defined as a decision by a market participant not to offer available generation capacity into the market when the short-run marginal cost of the capacity is less than or equal to the competitive market price.

[19] Abuse of Dominance Enforcement Guidelines, Canadian Competition Bureau, 2019.
[20] A variant of economic withholding is pricing up. Pricing up refers to a situation in which the marginal supplier raises its offer price above its short-run marginal cost, but just below the offer price of the next supplier. Pricing up results in a wealth transfer from all consumers to all suppliers in the market at the time. However, it does not necessarily lead to inefficient dispatch.

In both cases, the market participant effectively restricts its output to affect the market clearing price. Withholding (economic or physical) creates an artificial scarcity in the market. Withholding leads to a higher market price and thus to a wealth transfer from all consumers to all suppliers in the market during the affected period. It also results in inefficient dispatch when higher-cost sources of energy are called to market before lower-cost resources. To the extent that consumers respond to a price that (due to withholding) is above marginal cost by substituting to other forms of energy or by foregoing otherwise productive activities, this results in inefficient consumption decisions.[21]

The MSP monitors for evidence of the exercise of market power (withholding) as part of its evaluation of the overall efficiency of the IESO-administered markets. The MSP further monitors for the exercise of market power to determine whether corrective competitive responses are being impeded by market structure, rules or procedures or other barriers. This could lead to recommendations that the market rules or aspects of market design or overall structure be changed. [22]

The MSP applies a three-part test to identify a potential exercise of market power that consists of a Conduct Test, a Material Price Impact Test and a Profitability Test.[23] The Conduct Test examines the behaviour of market participants, to assess if they are engaged in withholding (economic or physical) or pricing up. The Material Price Impact Test assesses whether the conduct of a particular participant had a significant impact on the market price, raising it substantially. The Profitability Test analyzes whether the participant's conduct benefited the participant through increased profits. In conducting the Profitability Test, the MSP considers the effects of a

[21] Under the legacy market design, a market participant may, under certain market conditions, have had the ability to increase its Congestion Management Settlement Credit payments by offering supply at a price above or below its actual short-run marginal cost. This was called Local Market Power, and the IESO had responsibility over Local Market Power as was set out in Appendix 7.6 of the IESO's legacy market rules. While Section 1.8.1 of that Appendix 7.6 contemplated an MSP investigation or inquiry pursuant to the Appendix, no registered market participant could as a result of such activity, analysis or investigation, be subject to the imposition of any financial sanction by the IESO other than the revision of a settlement credit effected in accordance with Appendix 7.6.

[22] The exercise of market power may be reviewable by the IESO's MACD group and subject to remedial action.

[23] Monitoring Document: Monitoring of Offers and Bids in the IESO-Administered Electricity Markets, Market Surveillance Panel, March 2010.

participant's contract with the IESO or the regulated payment amounts in the case of Ontario Power Generation (OPG).

Furthermore, the MSP's identification of the persistent exercise of market power by a market participant may be the starting point for the assessment or investigation of a potential abuse of market power (i.e., to determine if the ability to exercise market power was achieved or enhanced by an anti-competitive act).

Under the renewed market, the IESO has implemented a new market power mitigation framework. Section 3 provides further information on the IESO's new framework and offers insights into the MSP's role under this framework.

2.4.1 Competition and Efficiency Analysis

A central focus of the MSP is to monitor for features of the IESO-administered markets that adversely affect the competitiveness of the markets and market efficiency. Competition and efficiency are fundamental principles in economics, indicating how well resources are allocated and how well businesses operate in a market. The MSP draws on these economic principles in its assessment of the IESO-administered markets.

Competition can be defined as a rivalry where two or more parties strive for a common outcome (consumer purchases) that cannot be shared. The competitiveness of a market is generally assessed according to the following factors:

- Number of sellers and buyers: Consumers have greater choice the more sellers there are in a market, which fosters greater competition between the sellers to win over consumer choice. Similarly, sellers have more options when there are more buyers in a market, which makes their business more viable.
- Ease of entry: Low barriers to entry, including low start-up capital costs and minimal regulations, can encourage new sellers to join a market, which in turn puts competitive pressure on the existing firms in a market.

- Information availability and transparency: When all buyers and sellers have complete and accurate information on the market conditions affecting product availability and current and future prices, they can make more informed choices, leading to greater competition. If one seller has better information on key market conditions, they are more likely to exploit this knowledge to their advantage and at the expense of others, which reduces the trust in the market and the willingness to consume or sell in the market.
- Product differentiation: When the sellers' products are similar, meaning consumers view one seller's product to be a good substitute for the products of all other sellers, consumers have greater choice, and sellers must compete more vigorously for consumer choice.

When these factors align with those of a more competitive structure, buyers and sellers have no, or at least minimal ability, to control market prices, and the prevailing market prices tend to reflect the marginal cost of production (i.e., there is an absence of market power). In this regard, the competitiveness of a market can be assessed in terms of evidence of the absence of a significant and sustained exercise of market power.

Competitive markets promote market efficiency, whereby supply is drawn from the lowest cost sellers at any point in time and the output is allocated to those with the highest valued uses. Over time, consumption from more efficient sources of supply and from superior new technologies drives out the less efficient sources. In an efficient market, the collective welfare of consumers and suppliers is maximized.

There are certain technical features of the electricity industry that makes electricity markets different from general economy "free markets."[24] These technical features have implications for the emergence and operation of

[24] See *Making Competition Work in Electricity*, Sally Hunt, New York Wiley, 2002, page 29. In particular:
- The flow of electricity must respect the physical laws governing the electricity network (frequency, voltage, stability), and supply and demand must always be in balance;
- Electricity is difficult to store (economically), particularly by end-use consumers;
- Real-time demand is very inelastic (i.e., does not respond to prices), however demand can change rapidly hour to hour;
- Electricity must be available on demand with "just-in time" production; and
- Random real-time failures in generation/transmission equipment that can disrupt the stability of the grid are possible.

competitive electricity markets. Whereas general economy markets can emerge and function with minimal or occasional regulatory oversight, electricity markets require constant oversight by a designated regulator (i.e., a system and market operator). Electricity markets do not emerge autonomously. Instead, they are regulatory constructions, designed by system operators, academics and stakeholders, and approved by regulators or government. They require market rules and system operator procedures to govern the buying and selling of electricity and to define the roles of participants, how electricity is priced and how the system is operated.

Ontario's wholesale electricity market is particularly unique. Ontario's market is a hybrid market that combines a competitive wholesale market with long-term planning and IESO procurement contracts. It also includes a provincially owned, rate-regulated generator that controls roughly 51 per cent of the province's generation capacity.

The market rules, IESO procedures and contracts influence (often intentionally) the decisions of electricity market participants; they affect how competition among participants occurs. The MSP must account for these influences when assessing the competitiveness of the IESO-administered markets. In particular, the MSP considers the extent to which the rules, procedures and contracts induce a participant to behave (i.e., bid or offer) as if it was competing in a perfectly competitive market (i.e., bidding or offering in a manner that reflects its true value of consumption or its marginal cost of generating). Assessing competitiveness in this manner puts the emphasis on the ultimate outcome of a competitive market, which is economic efficiency.

In electricity markets, economic efficiency is often discussed in terms of dispatch, consumption and investment efficiency. Dispatch efficiency (productive efficiency) occurs when electricity demand is supplied moment-by-moment by the lowest cost available generation sources. Consumption efficiency (allocative efficiency) occurs when only consumers that value electricity consumption equal to or more than the system marginal cost consume, and those that value electricity consumption less than system marginal cost do not consume.[25]

[25] The system marginal cost is the cost to produce one more unit of electricity at a point in time and at a specific location on the grid.

Dispatch and consumption efficiency are short-run measures of efficiency. In the short-run, generator, consumer and transmitter decisions are made based on the existing stock of assets (i.e., consumer devices and total generation capacity, along with transmission capacity). In response to market conditions, these participants seek to do the best they can, given the fixed stock of assets. In contrast, in the long-run, participants can change the stock of assets, selecting new assets or retiring old assets. Investment efficiency occurs when participants, over the long-run, invest in assets in a manner that ensures that industry resources are allocated in a way that maximizes overall societal benefit over time (i.e., promote dispatch and consumption efficiency over time).

In Ontario's hybrid market, investment decisions are largely influenced by central planning and government procurement directives. However, short-run prices can inform investment. The MSP's observations in support of short-run efficiencies and efficient pricing, therefore, supports long-run efficiency. Where competitive procurements (including the IESO Capacity Auctions) are used, the MSP assesses the competitiveness of the design and structure of the procurements, and the incentive effects of the contracts or financial arrangements for inducing competitive behaviour in the IESO-administered markets. The MSP believes that a competitive process should be the default procurement approach, barring other non-efficiency objectives.

2.4.2 Examples of Monitoring Indicia

The following offers a sample of key indicia used to monitor and identify anomalous market outcomes and anomalous or inappropriate conduct, and to assess the competitiveness and efficiency of the markets under the legacy market design. The MSP will continue to use several of these indicia to monitor the renewed markets. This summary is intended to offer the reader a sense of the monitoring activities of the MAU and the MSP over the past 20 years. Section 3 provides information on additional data series and indicia that the MSP will employ for the monitoring of the renewed markets.

2.4.2.1 Energy Market Prices and Price Movements

The energy market clearing price is the consequence of all market actions. An evaluation of the causes of an energy market price and energy price movements over time is therefore a reasonable starting point for identifying

potential anomalous or inappropriate market conduct, and features of the market that may adversely affect competition or market efficiency.

The evaluation typically involves a consideration of whether an energy clearing price or energy price movements over time can reasonably be explained by the fundamentals of supply and demand and an effectively competitive market. This assessment may be performed manually, by reviewing changes in five-minute or hourly supply-and-demand data,[26] or more systematically by using historic data and statistical relationships to identify and assess price outcomes that fall outside standard statistical confidence intervals. In either case, if it is determined that a certain clearing price or price movements cannot be readily explained by standard competitive supply and demand factors, a more detailed assessment of specific factors is conducted.

Under the legacy market design, the MSP used indicia such as hourly prices above the marginal cost of the highest cost fossil generation facility as a potential anomalous hourly price for further study.[27] The MSP has also monitored longer-term (daily, monthly, seasonal, annual) price trends using statistical measures of deviations from statistical norms (i.e., confidence intervals) to identify potential anomalous prices for further study.

As will be discussed in Section 3, the shift from a uniform energy market clearing price to a system of locational marginal prices, zonal prices and an Ontario Zonal Price for non-dispatchable loads will change the mechanics by which pricing indicia are monitored but not the general approach.

2.4.2.2 Offered Cost vs. Estimated Cost

A standard metric used by market monitors, including the MSP, is a comparison of offer prices (offered costs) and estimated costs. Supply offered at prices above estimates of short-run marginal cost may be an

[26] Supply factors can include fuel availability for hydroelectric, wind and solar generation, natural gas prices, nuclear generation availability, generation outages (planned and forced) and import availability. They can also include a consideration of transmission limits. Demand factors include dispatchable and non-dispatchable demand and factors that influence that demand, including weather and export availability. Pre-dispatch forecasts and scheduling decisions are also considered as affecting supply-and-demand factors that in turn affect real-time prices.
[27] In its first report in 2002, the MSP selected $200/MWh to define an anomalous price, as this price was well over three times the average Hourly Ontario Energy Price at that time and above the incremental cost of the highest cost fossil generating unit in the province. See Market Surveillance Panel Monitoring Report On The IMO-Administered Electricity Markets for The First Four Months May- August 2002, October 2, 2002, page 70.

indication of a possible exercise of market power, an abuse of market power or gaming, all of which may contribute to inefficient market outcomes. Supply offered at prices above or below short-run marginal cost may also be an indication that the market design, rules, IESO contracts or other market factors are distorting the incentives for suppliers to offer competitively and efficiently, which may point to possible flaws in these market structures.

The MSP recognizes there are several practical issues to be addressed in the estimation of marginal cost. Marginal cost estimates derived from engineering studies can fail to properly account for a supplier's competitive considerations related to its need to recover average incremental cost and opportunity cost. Cost estimates inferred from past offer behaviour may also fail to capture incremental cost and opportunity cost.

Under the market rules of the renewed markets, market participants are required to submit to the IESO information on production costs, unit characteristics and opportunity costs as part of the market power mitigation framework. This new information will assist the MSP in its assessment of marginal cost.

2.4.2.3 Congestion Management Settlement Credit Payments

Congestion Management Settlement Credit payments (CMSCs) were a key feature of the legacy two-schedule market design that prevailed until implementation of the renewed markets. Like energy prices, they are a consequence of market actions. Various thresholds have been used in the past to triage, for further review, instances of high individual CMSCs paid to a market participant or periods of high CMSCs paid in the market. High CMSCs may have been an indication of the presence of local market power or gaming. They may also have been an indication of flaws in the overall structure (limited transmission infrastructure, flaws in the generation or transmission outage planning process or other market design flaws).

The MSP has monitored for large CMSCs in the overall market, in certain electrical zones or paid to individual market participants, on an hourly, daily and seasonal basis, as triggers for further study of potential flaws in the market or inappropriate conduct. CMSCs were eliminated with the implementation of the renewed markets, with the effects of congestion being

reflected in locational marginal prices or Make-Whole Payments. Section 3 discusses how the MSP's monitoring will be affected by this shift.

2.4.2.4 Marginal Unit Analysis

Marginal unit analysis identifies the cost of the resource that would be dispatched to meet the next increment of demand (i.e., the marginal unit). Marginal unit analysis can be important for understanding how prices are set and the efficacy of the price-setting process. In the renewed market, with locational marginal pricing, the MSP will consider identifying the marginal units for each location and within each pricing zone.

2.4.2.5 Structural Measures of Competition

The MSP will continue to apply measures to assess the competitive structure of the electricity market. Some of these are commonly used to assess market concentration and competition in industries other than the electricity sector. These measures were applicable in the legacy market and will continue to be applicable in the renewed market. Other measures are more unique to the electricity sector. Structural measures used by the MSP include:

- Herfindahl-Hirschman Index (HHI): The HHI is a standard tool used to characterize the concentration of market share in various industries.[28] In the context of the Ontario electricity market, the MSP routinely applies the HHI to evaluate the concentration of control over generation assets – both at a provincewide scale and within each of the major transmission zones that comprise the electricity system. In a zonal context, HHI values are an initial indicator of where within the electricity system there may be a greater likelihood or frequency of the exercise of local market power.
- Residual Supplier Index (RSI): The RSI is a metric used to assess market competitiveness and market power in electricity markets. It is calculated as the ratio of total market supply capacity (excluding a specific market participant's capacity) to the market demand at a specific time and in a specific location. The RSI provides a measure of

[28] The HHI is calculated by squaring the market share of each firm in a market, summing the resulting numbers and then interpreting the total as an indicator of market concentration. A higher HHI indicates a more concentrated and possibly less competitive market while a lower HHI suggests a less concentrated and possibly a more competitive market.

the importance of the excluded market participant's production for meeting market demand. The lower the RSI value, the less likely the market is competitive and the more likely the market participant can influence the market price above the competitive price level. An RSI score of less than one indicates that market demand cannot be satisfied without the production of the market participant (i.e., the market participant's production is "pivotal" for serving demand and it has the ability to significantly influence the price upward above the system marginal cost). The MSP has applied the RSI at a provincewide scale and within each of the major transmission zones that comprise the electricity system.

- Regulatory measures: Since the commencement of Ontario's electricity market, certain legacy generation assets controlled by OPG and its subsidiaries have been subject to measures that influence OPG's operations in the IESO-administered markets. These measures are somewhat unique to the Ontario market. The MSP regularly considers these measures when monitoring the markets to assess OPG's incentives to offer efficiently.
- Contractual measures*:* Most of the generation and storage facilities, and some load facilities, in Ontario are under contract with the IESO. The terms of these IESO contracts can influence how owners of these facilities operate in the IESO-administered markets. The MSP regularly considers contractual terms when monitoring the markets to assess the terms that affect the incentives for these participants to offer or bid efficiently.

2.4.2.6 Efficiency Assessments

To assess the potential inefficiency that may result from flaws in market design, market rules and procedures, and overall structure (market flaws) or inappropriate conduct, the MSP applies a "but-for" analysis. This analysis was applicable in the legacy market and will continue to be applicable in the renewed markets. A "but-for"" analysis is used to determine if a specific event or outcome would have occurred without the presence of a particular factor or action. In the context of the electricity market, the MSP's "but-for" analysis compares actual observed market outcomes to the outcomes expected to prevail absent the market flaw or conduct:

- Dispatch efficiency: To assess the dispatch efficiency of a market feature of participant conduct, the MSP compares the actual production cost incurred to meet demand over a review period when the feature or conduct was present (i.e., five-minute interval, hourly as the sum of the 12 five-minute intervals, multi-hourly, daily, monthly, etc.), to an estimate of the production cost that would have been incurred "but-for" the market feature or conduct. This analysis generally requires consideration of how market participants, the IESO or other affected parties would have responded (offered, bid, etc.) had the market feature or conduct not been present. The difference between that actual production cost versus the estimated but-for production cost represents the efficiency loss (if positive) or the efficiency gain (if negative).
- Consumption efficiency: To assess consumption efficiency, the MSP compares the actual amount of electricity consumption that occurred under the market feature or conduct over the review period, to an estimate of the amount of electricity that would have been consumed "but-for" the market feature or conduct. The area below an estimate of the electricity demand curve between the actual consumption amount and the estimated but-for consumption amount represents the efficiency loss.
- Investment efficiency: Investment efficiency is often assessed with reference to long-run marginal cost.[29] Long-run marginal cost represents the cost of producing an additional unit of electricity in the long run, and market prices should ideally reflect these costs. The MSP has frequently noted that long-run investment efficiency is achieved when the industry's long-term average cost is minimized and price equals marginal cost, promoting efficient resource allocation.

2.5 Investigations

Section 37 of the *Electricity Act, 1998,* provides the MSP with the powers to investigate any activity related to the IESO-administered markets or the

[29] For example, see A Comparison of the Long-Run Marginal Cost and Price of Electricity in Alberta: An assessment undertaken as part of the 2012 State of the Market report, Market Surveillance Administrator, December 10, 2012.

conduct of a market participant. Section 5.1.1 of By-law #2 further provides that the MSP may commence an investigation:

- Where it considers such investigation is warranted as a result of its monitoring activities
- At the request of the CEO of the OEB
- Upon receipt of a complaint or referral from any person other than the CEO, or any board, agency or tribunal.

The MSP has broad discretion in establishing the scope of an investigation, determining whether to commence or terminate an investigation in appropriate cases and making findings regarding the activity or conduct in question. A person under investigation has a right to be notified (unless it would prejudice the investigation) and to have an opportunity to respond where the MSP intends to make a finding that the person has engaged in inappropriate or anomalous conduct. The CEO of the OEB is required to be kept informed of the progress of, and all major steps taken during, an investigation.

For the purposes of an investigation, the MSP has the power to examine any documents or other things, whether they are in the possession or control of the person whose activities are being investigated or any other person. The MSP also has the same power to summon and enforce the attendance of any person and to compel them to testify on oath or otherwise, and to summon and compel any person to produce documents and other things, as is vested in the Superior Court of Justice for the trial of civil actions. The MSP may also conduct on-site inspections and apply for a warrant authorizing search and seizure.

The output of an investigation is a report that is provided to the OEB and to the IESO. With notice to the CEO of the OEB, the MSP may also send the report to any other person the MSP considers appropriate, as may the CEO of the OEB. Investigation reports are made public on the OEB's website (subject to redactions for confidentiality). Upon receipt of an investigation report that contains recommendations relating to the abuse or possible abuse of market power, the IESO must inform the OEB about actions that it has taken or intends to take in response to the report. The OEB may conduct a

review to determine whether the market rules or licence of any market participant should be amended.

The MSP does not have powers to take remedial actions or impose sanctions on market participants or the IESO as part of its investigation powers; it only has the power to make recommendations. The powers to take remedial action or impose sanctions rest with the OEB and MACD.

Since market opening, the MSP has conducted seven investigations: two investigations on its own initiative stemming from its monitoring of market participant conduct; three investigations at the request of the CEO of the OEB; and two based on a referral from a third party. The MSP received a third referral but determined upon review of the circumstances in the case not to commence an investigation.

2.6 Reviews

Section 6.1.1 of By-law #2 provides that the MSP, with prior concurrence from the CEO of the OEB, may undertake a review of actual or potential design flaws or inefficiencies in the market rules and procedures of the IESO, or of design or other flaws in the overall structure of the IESO-administered markets, as identified through its monitoring activities. The MSP must prepare and deliver a report on its review to the CEO of the OEB, with information on the matter reviewed, the manner in which the matter came to the MSP's attention, the MSP's findings and any MSP recommendations with reasons. The CEO of the OEB must provide the report to the IESO and to other persons the CEO considers appropriate, and the report must be posted on the OEB's website, subject to the redaction of confidential information.

3 MONITORING OF THE RENEWED IESO-ADMINISTERED MARKETS

3.1 The IESO's Market Renewal Program

The IESO's established mission for the MRP is to "deliver a more efficient, stable marketplace with competitive and transparent mechanisms that meet system and participant needs at lowest cost."[30]

To deliver on its mission, MRP is intended to:[31]

- "Replace the two-schedule market with a single-schedule market (SSM) that will address current misalignments between price and dispatch, eliminating the need for unnecessary out-of-market payments.
- Introduce a day-ahead market (DAM) that will provide greater operational certainty to the IESO and greater financial certainty to market participants, which lowers the cost of producing electricity and ensures we commit only the resources required to meet system needs.
- Reduce the cost of scheduling and dispatching resources to meet demand as it changes from the day-ahead to real-time through the enhanced real-time unit commitment (ERUC) initiative." [32]

In addition, the IESO has introduced a new market power mitigation framework to address the potential for suppliers to exercise market power in the energy and operating reserve markets.[33]

The following provides a high-level synopsis of the key design differences between the legacy markets and the renewed markets.

[30] Market Renewal Mission and Principles, accessed on March 24, 2025.
[31] What is the Market Renewal Program? (ieso.ca).
[32] Single Schedule High-Level Design, August 2019.
[33] Market Renewal Program: Energy, Market Power Mitigation, Detailed Design, Issue 2.0.

3.1.1 Two-Schedule vs. Single-Schedule System[34]

The legacy market design used two separate schedules: one for determining dispatch instructions and another for determining a uniform Ontario price used for settlement. The IESO acknowledged that the two-schedule system had a "misalignment between price and dispatch,"[35] leading to inefficiencies and the need for complex out-of-market payments.

In the renewed markets, the IESO uses a single schedule to determine both dispatch instructions and prices, which the IESO expects will improve the alignment of price and dispatch.

The SSM introduces locational marginal prices (LMP) for dispatchable market participants. LMPs are designed to reflect the as-offered cost (or bid price) of producing and consuming one more megawatt of electricity at a specific location at a point in time. Each LMP is calculated to include three components:

- The energy reference price: The cost of increasing the demand for electricity by one megawatt at the "reference location," the Richview Transformer Station located in the Greater Toronto Area.
- The energy price congestion: The component that is the incremental cost at any location on the grid due to transmission congestion between that location and the reference location (which may be positive or negative).
- The energy price loss component. This reflects the cost of marginal transmission losses at a given location relative to the reference location.[36]

Under the SSM, differences in real-time LMPs at different locations can vary based on congestion and losses relative to the reference location.

Non-dispatchable loads, including local distribution companies, are settled in the SSM using the Day-Ahead Ontario Zonal Price (OZP) plus a price adjustment called the Load Forecast Deviation Adjustment (LFDA). The OZP

[34] Single Schedule High-Level Design, August 2019.
[35] Ibid. page 7.
[36] Paraphrased from IESO, *Single Schedule Market High-Level Design.*

is the summation of the reference price plus the load-weighted averages of the loss and congestion components of LMPs at non-dispatchable load locations, effectively spreading the cost of serving these loads across all non-dispatchable loads.[37]

By aligning price and dispatch, the SSM aims to reduce the need for unnecessary out-of-market payments.[38] Furthermore, the SSM has enabled the IESO to implement other initiatives, including the day-ahead market.

3.1.2 Legacy Day-Ahead Commitment Process vs. Day-Ahead Market[39]

The key difference between the IESO's legacy day-ahead commitment process (DACP) and the new DAM is that the DAM is a financially binding market open to all market participant classes, while the DACP was not.

Under the legacy DACP, certain dispatchable facilities, namely non-quick-start generators and importers, that were eligible for a production cost guarantee could receive a commitment schedule one day ahead. If they met that schedule in real time, they were kept financially whole to their day-ahead offer. Other generators, dispatchable loads and exporters were not eligible for guarantees. The DACP aimed to provide a dependable view of the next day's available supply and anticipated demand for eligible participants and the IESO.

The IESO has acknowledged that the legacy DACP had several shortcomings. The inability to obtain a financially binding price reduced the incentives for exports, dispatchable loads and quick-start generators to participate fully or efficiently in the DACP. Instead, these resources made decisions on participating in the real-time markets based on real-time price expectations. The IESO noted that "failure of resources to participate fully or efficiently in the DACP results in an incomplete view of the next day's demand and supply, diminishing the IESO's ability to schedule and commit the lowest-cost set of resources to meet the next day's demand."[40]

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[37] Ref. IESO, Renewed Market Rules, Chapter 0.9 section 3.2, and Chapter 0.7 Appendices, sections 11.3.3.2, 16.3.3.2, and 23.3.3.3.
[38] IESO, Single Schedule Market High-Level Design, page 13.
[39] Day-Ahead Market High-Level Design, August 2019.
[40] Day-Ahead Market High-Level Design, August 2019, page 4.

The IESO's DAM features a new DAM calculation engine,[41] financially binding prices, and a process where market participants submit bids and offers a day in advance, which the IESO expects will lead to better resource planning and improved scheduling efficiency.

The DAM calculation engine runs on the pre-dispatch day and produces schedules and locational marginal prices for every hour of the dispatch day, resulting in financially binding prices. The DAM calculation engine uses new inputs from market participants. This includes dependencies between different hydroelectric resources on a cascade river system, the minimum level of output to which a hydroelectric resource can be scheduled, and new inputs specifying the number of hours it takes for a non-quick start resource to reach minimum loading point.[42]

New IESO data inputs are also utilized by the DAM calculation engine, including an enhanced network model providing pricing locations for all delivery points associated with dispatchable generation facilities, dispatchable loads, non-dispatchable generation facilities, non-dispatchable loads and price responsive loads, and new demand forecasts produced as the sum of four separate area demand forecasts to better reflect localized weather conditions and consumption patterns for each area.[43]

The DAM also permits participation by virtual traders, which are market participants who submit financial bids and offers for energy, like physical resources, but without physically withdrawing energy from or injecting it into the grid. Virtual trading is intended to improve participation and competition in the DAM, and to bring price convergence between day-ahead and real-time pricing.

[41] Under "The Renewed Market Rules for the Ontario Electricity Market," the day-ahead market calculation engine means an algorithm that consists of three passes, where each pass executes one or more optimization problems solved by the IESO to determine schedules and prices in accordance with MR Ch.7 App.7.5 to meet the needs of the day-ahead market. The renewed market rules provide similar definitions for the pre-dispatch and real-time calculations.
[42] Paraphrased from, IESO, Market Renewal Program: Energy Day-Ahead Market Calculation Engine Detailed Design, Issue 2.0, page 8.
[43] Ibid.

3.1.3 Legacy Unit Commitment vs. Enhanced Real-time Unit Commitment [44]

Unlike the previous pre-dispatch and unit commitment processes, the ERUC aims to "improve the efficiency of unit commitments"[45] in the intra-day timeframe by optimizing over multiple hours and considering all resource costs, unlike the legacy pre-dispatch and unit commitment processes.

The legacy unit commitment process solved each hour independently, potentially leading to suboptimal decisions across multiple hours. It did not fully account for or optimize all relevant costs, including fixed start-up costs and speed-no-load costs of non-quick-start resources, in commitment decisions.

The IESO expects the ERUC will improve competition and produce more efficient market outcomes, facilitate the scheduling of the lowest-cost resources to meet reliability needs in real time and address issues arising from enforcing DAM requirements, particularly for non-quick-start resources.[46]

3.1.4 Market Power Mitigation Framework[47]

The IESO has introduced a new market power mitigation (MPM) framework to address the potential for suppliers to exercise market power in the energy and operating reserve markets. The IESO's purpose for implementing the MPM framework is to prevent electricity suppliers from exerting undue influence on market prices due to their location on the transmission grid, ensuring a more efficient and competitive electricity market.[48] The new MPM framework consists of:

- An ex-ante (before-the-fact) approach to market power mitigation to be applied in the day-ahead, pre-dispatch and real-time scheduling

[44] See IESO, Enhanced Real-time Commitment High-Level Design.
[45] See IESO, Enhanced Real-time Commitment High-Level Design, page 54.
[46] Ibid. page 5.
[47] Market Manual 14: Market Power Mitigation Part 14.1: Market Power Mitigation Procedures, Issue 7.0 June 7, 2024, accessed on March 24, 2025.
[48] Market Manual 14: Market Power Mitigation Part 14.1: Market Power Mitigation Procedures, Issue 4.0 September 9, 2022, accessed on March 24, 2025. The MPM framework includes a conduct and price impact test that is like the MSP's tests. The IESO's MPM framework does not include a profitability test or consider the extent to which contracts or regulation could be a mitigating circumstance for the conduct.

processes. This is intended to "…address situations where market power could affect dispatch schedules and prices in the energy and operating reserve markets" [49]

- An ex-ante settlement mitigation process to address situations where market power could impact the settlement of Make-Whole Payments (see 3.2.3 below for a discussion of these payments)
- An ex-post (after-the-fact) mitigation of market power to "…alleviate the effects of physical withholding…"[50] and the effects of economic withholding on uncompetitive interties.[51]

3.2 Monitoring the Renewed IESO-Administered Markets

The MSP's mandate, to monitor the IESO-administered markets for anomalous market outcomes, anomalous or inappropriate market participant conduct, market flaws or IESO activities that impact or are inconsistent with the efficient and fair operation of a competitive market, carries forward in the renewed markets. However, the various changes made to the IESO-administered markets through MRP have required the MSP to incorporate new indicia and tools to monitor the renewed markets. The following provides a sample of the additional data series, indicia and analytic tools that the MSP will employ in monitoring the renewed markets. As noted in Section 2, some of the indicia and tools used in monitoring the legacy markets will remain relevant in the renewed markets.

3.2.1 Locational Marginal Prices and Zonal Prices

Under the renewed markets, DAM, pre-dispatch and real-time prices shift from unconstrained, Ontario-wide prices to locational marginal prices (LMPs) and zonal prices which are variously applicable to different classes of market participants. The MSP will continue to use indicia such as the cost of the highest cost peaking natural gas generators as an initial screen to trigger study of potentially anomalous LMPs. The MSP will use different statistical models of individual LMP trends to identify price trends that fall outside of statistical norms. Additionally, the MSP is exploring new statistical modeling

[49] IESO, Market Renewal Program: Energy - Market Power Mitigation Detailed Design, Issue 2.0, page 7.
[50] Ibid.
[51] Ibid.

to compare sets of LMPs and zonal prices, on an hourly basis and across different time frames, to assess potentially anomalous LMP differences that are not readily explained by losses or congestion. This type of monitoring analysis will replace the monitoring of legacy CMSCs to assess potential market flaws or inappropriate conduct not explained by grid conditions.

In the renewed markets, the IESO uses new reserve shortage penalty prices to address constraint violations, including: a maximum operating reserve area penalty price, a penalty price for 30-minute operating reserve and an area minimum operating reserve penalty price.[52] The IESO uses reserve shortage penalty prices to ensure that day-ahead, pre-dispatch and real-time calculation engines respect mandatory reserve requirements and that prices signal those requirements, and to encourage market participants to meet reliability obligations. Other penalty prices influence the calculation engines to avoid scheduling solutions that violate other physical constraints including transmission security constraints, daily energy limits of facilities and overall energy balance.[53] Most penalty prices used are all greater than the maximum market clearing price and are not used for market settlement. When an LMP is inflated above the maximum market clearing price for scheduling purposes, as a result of a penalty price violation, it is adjusted to a “settlement ceiling price.”[54] Conversely, if an LMP is depressed below a defined “settlement floor price” (e.g. due to energy imbalance during over-generation conditions), it will be adjusted to that floor price for settlement purposes.[55] The MSP will review all outcomes when the reserve shortage penalty prices are applied to identify the causes for the shortages and potential anomalies in market design or inappropriate conduct used to drive up prices.

3.2.2 Internal Congestion Rents

Congestion rents occur when binding transmission constraints create price differences (i.e., differences in LMPs). When a transmission constraint is binding, lower-priced supply on one side of the constraint cannot fully serve demand on the other side. This demand must be served by higher-priced

[52] IESO Market Manual 4: Market Operations Part 0.4.3: Operation of the Real-Time Market, Issue 1.0 November 11, 2024.
[53] Ibid.
[54] IESO renewed Market Rules, Appendix 7.5, section 23.3.1.4.
[55] Ibid.

supply on the demand side of the constraint. When this occurs under the renewed markets, consumers will be charged the higher LMP for all their demand. However, suppliers dispatched on the lower-priced side of the constraint to supply part of the demand will receive the lower LMP. The difference between the higher amount paid by consumers and the lower amount paid to suppliers is called a congestion rent. The IESO will collect internal congestion rents and return them to Ontario consumers monthly, proportional to their consumption.[56]

Internal congestion rents provide information on the potential economic benefit from new investment in internal transmission. The MSP will monitor and report on this information as it relates to the overall efficiency and competitiveness of the IESO-administered markets.

3.2.3 Make-Whole Payments

Make-Whole Payments (MWPs) are a financial mechanism to encourage market participants to follow their dispatch instructions, even if doing so leads to higher participant costs or lost opportunities, by ensuring they are financially "made whole." MRP will introduce both day-ahead MWPs for resources scheduled in the DAM, along with real-time MWPs for resources following their dispatch instructions under ERUC and in the real-time markets. As noted in Section 2, CMSC payments, which were intended to encourage participants to follow dispatch under a two-schedule system in the face of transmission constraints, will be eliminated and replaced by LMPs, which embed the cost of congestion, and MWPs, which will provide compensatory payments for incremental costs incurred or lost opportunity costs when the IESO dispatches resources out-of-merit to manage congestion or reliability-related issues.

Like the MSP's monitoring of CMSCs in the legacy market, the MSP will monitor large MWP amounts in the overall market and in certain electrical zones, as well as MWPs paid to individual market participants or in respect of specific facilities, on an hourly, daily and seasonal basis, as triggers for further study of potential flaws in the market or anomalous or inappropriate conduct.

[56] Single Schedule High-Level Design, August 2019, accessed on March 24, 2025.

To monitor the overall MWPs for potential anomalies, the MSP will calculate on a daily, monthly and annual basis for both DAM and real-time, the following indicia:

> *MWP Anomaly Index* = MWP ÷ (Resource Revenues + MWP) x 100.
>
> This index compares the level of MWP to the resource revenues plus MWPs, putting the level of MWPs in perspective relative to resource margins. This metric will tend to filter out changes in the level of MWPs due to variations in fuel costs and as well as those due to the frequency with which particular types of units are committed, to better identify potential anomalies and changes in behaviour.

The MSP will pay particular attention to MWPs made because of unit commitments in both the DAM and ERUC, and units committed or dispatched out-of-market by IESO control room operator actions. MRP is intended to improve the representation of facilities' operational characteristics and parameters in the day-ahead, pre-dispatch and real-time calculation engines, and the resulting price signals. MWPs made due to operator actions may be an indication of potential limitations in MRP design or physical realities not modeled in the calculation engine or submitted dispatch data. This information can also be used to do ex-post assessments of the need for and efficacy of out-of-market IESO control room operator actions.

The MSP will monitor frequent or large MWPs made to specific market participants or traders, or in respect of specific facilities or import or export transactions, to assess the causes of the payments including potential design flaws or inappropriate conduct

3.2.4 Operating Characteristics and Parameters

In the renewed markets, non-quick-start generation facilities, hydroelectric facilities and variable generation facilities, will be required to submit new (additional) data on operating characteristics and parameters. This new data will be used in the day-ahead and real-time calculation engines to ensure that security-constrained dispatch and associated LMPs better reflect the realities of the electricity system and reduce the need for out-of-market intervention by the IESO.

The MSP will monitor changes to individual facility data to assess the effects that the changes may have on dispatch and economic efficiency. Changes to this data may be part of a broader strategy by a market participant to inappropriately influence market outcomes, MWPs and prices to the benefit of the participant and at the cost or expense of other market participants and consumers.

3.2.5 Market Control Entities

A market control entity (MCE) is any entity (registered as a market participant with the IESO or not) that could control or influence the offers and schedules of one or more market participants in the day-ahead and/or real-time market through, for example, an ownership, controlling, subsidiary or beneficial interest relationship.[57] Under the renewed markets, market participants must disclose MCEs for resources that are generation resources, dispatchable loads, price responsive loads, electricity storage resources, energy traders or virtual traders. The IESO will use this data when assessing physical withholding, where the offer quantities of resources that share a common MCE are assessed in aggregate.

To the extent that this new data provides greater insight into the ownership and control relationships of system resources, the MSP will incorporate the data in the calculation of structural measures of competition (i.e., Herfindahl–Hirschman index, Residual Supplier Index, etc.). Furthermore, to the extent that this data offers insights into profitability and beneficiary relationships, the MSP will use this data in assessing potentially inappropriate conduct such as the abuse of market power and gaming. This data may provide insights into which entities stand to profit from potential inappropriate conduct and the possible motives behind the conduct.

3.2.6 Day-Ahead to Real-Time Price Convergence

Ideally, DAM and real-time electricity prices should converge, meaning they should, on average, be similar over time. Convergence is desirable because:

- It signals a well-functioning market where participants can accurately forecast and react to real-time conditions

[57] Guide to Submitting New Registration Parameters and Forms In Online IESO, May 2025.

- Market participants who rely on day-ahead prices to make longer-term contractual commitments and investments can better manage longer-term price uncertainty and risk
- It discourages participants from artificially manipulating prices by waiting for better real-time conditions.

There are several mechanisms in the renewed markets that help facilitate convergence, including virtual trades, whereby market participants make financial trades in the DAM with the explicit requirement to buy or sell back in the real-time market, which pressures prices to converge.

Factors that can lead to divergence include the unpredictability of real time market conditions, insufficient trading volumes (illiquid markets) between DAM and the real-time markets, persistent differences in IESO demand forecasts or variable generation output forecasts between DAM and real-time, and gaming, whereby traders or entities intentionally influence prices by taking positions that disrupt the normal relationship between the markets.

The MSP will monitor persistent price differences between DAM and real-time to understand the underlying causes for the divergence, and to ensure that such differences are not a result of illiquid markets (i.e., few buyers and sellers or low trading volumes), persistent IESO forecast errors or inappropriate conduct such as gaming.

3.2.7 Market Analysis and Simulation Toolset

The IESO has developed new market simulation and analysis capabilities called the Market Analysis and Simulation Toolset (MAST) with MRP.[58] MAST enables the IESO to see and manipulate inputs into the underlying calculation engines of the new markets to conduct a “but-for” analysis of market outcomes. This new functionality is intended to provide the IESO with the tools to assess the effectiveness of the renewed markets and to identify potential solutions to address unintended outcomes and inefficiencies.

The MSP will have access to MAST and will seek to use it to assess potential anomalous market outcomes, anomalous or inappropriate conduct and

[58] IESO, Project Charter for: Market Analysis and Simulation Toolset (MAST), filing to the OEB, EB-2022-0002, Exhibit E-2-1 Attachment 3, Filed: March 4, 2022.

potential market flaws. The MSP may also use MAST to assess the overall efficiency of the newly renewed markets as part of its annual *State of the Market* reports.

3.3 Monitoring the IESO's Market Power Mitigation Framework

Through MRP, the IESO has introduced a new MPM framework, to address the potential for suppliers to exercise market power, both in an ex-ante and ex-post context.

The MSP will regularly monitor and evaluate the effectiveness of the MPM framework by applying the MSP's three-part test for the exercise of market power. The MSP will use IESO data on reference prices, constraint areas and MCEs to hone the effectiveness of the test. The MSP will use the three-part test to identify "false positives" and "false negatives." The MSP considers a false positive to have occurred when the IESO mitigates a participant's offer price ex-ante in either the DAM or real-time, and when the participant's offer did not trigger or fail the MSP's three-part test. The MSP considers a false negative to have occurred when the IESO does not mitigate a participant's offer price ex-ante in either the DAM or real-time, when the participant's offer did trigger or fail the MSP's three-part test.

3.4 General Efficiency and Competitiveness Assessment of the IESO-Administered Markets

Article 7 of By-law #2 requires the MSP, at least once annually, to provide a general assessment of the efficiency and competitiveness of the IESO-administered markets, which the MSP does in its annual *State of the Market* report.

The IESO's implementation of MRP is intended to improve the overall efficiency of the IESO-administered markets. In an upcoming *State of the Market* report, after sufficient data has been collected to permit such an analysis, the MSP intends to provide a comparison of the relative efficiency and competitiveness of the legacy markets to the renewed markets. This analysis is not intended to be an audit of MRP at achieving its objectives. Instead, it is intended to offer insights into the overall efficiency implications

of the changes, including where certain efficiencies may or may not have been realized and where improvements in design may be desirable.

Over the next year, the MSP will consider different modelling approaches to assessing the overall efficiency implications of the introduction of MRP, recognizing the challenges of doing a standard “but-for” analysis that can appropriately capture the significant changes to the markets that will have occurred.

4 SUMMARY REMARKS

The purpose of the MSP in Ontario's electricity sector is to monitor, investigate, review, and report on activities and conduct in the IESO-administered markets, which it does typically with a view to promoting market efficiency and effective competition. The role of the MSP does not change with the introduction of the renewed markets. The MSP will continue to fulfil its mandate, albeit with additions and adjustments to its monitoring indicia and tools, to account for the various changes introduced by MRP. The MSP will continue to report on the overall efficiency and competitiveness of the IESO-administered markets in its annual *State of the Market* reports. The MSP intends to provide a comparison of the relative efficiency and competitiveness of the legacy markets to the renewed markets, after sufficient data has been collected to permit such an analysis.

Appendix - MSP recommendations to the Legacy Market Design

Since the commencement of the electricity market in 2002, the MSP has regularly and publicly reported on the state of the IESO-administered markets through its reports, including specific recommendations to the IESO for changes to the legacy market design that would foster enhancements to market efficiency. These recommendations have resulted in incremental improvements, including:

- Reforms to the auctioning of transmission rights: Past MSP recommendations in this area centered around reforms to ensure that payouts under transmission rights remained in balance with congestion rents collected. Under MRP, the basis of transmission rights payouts has now moved to the DAM.
- Refinements to the applicability and calculation of CMSC: Many past MSP recommendations addressed the way CMSC bridged the gap between unconstrained market prices and constrained scheduling. A subset of these recommendations was put in place by the IESO prior to MRP implementation. The IESO expects that the remaining recommendations will be addressed by MRP itself (see Table A-1-1) as CMSC is made unnecessary with the implementation of locational marginal pricing.
- Reforms to the Generation Cost Guarantee (GCG) programs: Recommended reforms to the GCG programs (both day-ahead and real-time) were the single-largest subject area of past MSP recommendations. For many years, the MSP recommended that competitive pressure be brought to bear on generation unit commitments to avoid the issues associated with after-the-fact cost submissions. Some prominent reforms have already been brought about in response to MSP recommendations[59] while others are expected to be addressed through MRP implementation (see table A-1-1).

[59] For example, Monitoring Report on the IESO-Administered Electricity Markets for the period from May 2008-October 2008, January 2009, Recommendation 3-3.

Table A-1-1 contains a list of past MSP recommendations to the legacy market design that the IESO deferred to the implementation of MRP. All MSP recommendations are in the public domain and may be found within past MSP reports on the OEB's website.

Recommendations relevant to the Market Renewal Program

Several of the MSP's recommendations on observed inefficiencies reported over the past 23 years are aligned with many of the goals and objectives of the MRP. Indeed, the IESO has often cited MRP as the over-arching remedy to many of the MSP's published recommendations.

At least 18 past MSP recommendations have direct relevance to the introduction of MRP. As the table below points out, MSP recommendations going back to at least 2010 called for the following market reforms:

- Locational marginal pricing: For reasons discussed in this report, locational marginal pricing offers efficiency improvements and potentially resolves a number of issues in the legacy market. Expected improvements include more efficient pricing of congestion at the interties and accounting for operating reserve shortfalls in energy prices.
- More efficient unit commitment: Perhaps the largest category of MRP-related recommendations is related to the various generation cost guarantee programs. MRP will bring about new unit commitment mechanisms in the DAM and pre-dispatch that account for registered facility characteristics and submitted costs at the time unit commitment decisions are made, and bring competitive pressure to bear on such decisions. As noted in the table below, the absence of such competitive pressures and advance disclosure of production costs have resulted in numerous issues that have been the basis of MSP recommendations over the years.
- Improvements in other functional areas, including Intertie Offer Guarantees, pricing of operating reserve shortfalls and containment of gaming incentives**:** These areas were also subjects of past MSP recommendations where MRP-related functionality will likely have a significant impact.

Past MSP recommendations in these areas are also listed in Table A-1-1.

Table A-1-1: List of Past MSP recommendations directly related to MRP functionality

Report Issuance Date	Rec. No.	Recommendation
January 29, 2010	3-5 (i)	The Panel recommends that the IESO provide market participants with specific parameters for determining operating plant characteristics, including Minimum Loading Point (MLP), Minimum Run-Time (MRT) and Minimum Generation Block Run-Time (MGBRT) in order to ensure that submitted operating characteristics, which affect market outcomes, reflect actual operating capabilities.
January 29, 2010	3-5 (ii)	The Panel recommends that the IESO develop a compliance or other review mechanism for ensuring that submitted operating characteristics are appropriate having regard to the parameters specified and equipment capabilities.
August 30, 2010	3-4	To the extent that the IESO believes a reliability program such as the generation cost guarantee program continues to be warranted, the IESO should base the guarantee payment on the offer submitted by the generator or should implement another solution that would require actual generation costs to be taken into account at the time of scheduling decisions.
March 10, 2011	3-3	As part of its “market road map” process, the IESO should work with stakeholders to examine the feasibility of replacing the two-sequence design with locational pricing, variable pricing for dispatchable resources or other alternatives.
March 10, 2011	3-4(ii)	On an interim basis until after-the-fact start-up cost submissions are capped by generator offer prices and CMSC payments to ramping down generators are eliminated, the IESO should amend the Generation Cost Guarantee program to limit generators to one start-up cost guarantee submission per day unless the IESO requests a second start during the day.
April 27, 2012	4-1	The Panel recommends that the IESO proceed with development work on those recommendations of the Electricity Market Forum that are directed at improving market efficiency, including the consideration of options to replace the two-schedule structure of the current market design.
June 21, 2013	2-1	The IESO should consider expanding the current local market power framework to cover analogous circumstances that arise as part of the day-ahead commitment process.

Report Issuance Date	Rec. No.	Recommendation
January 6, 2014	3-2	If the IESO, after performing its detailed analysis, determines that the RT-GCG program continues to be needed, the Panel recommends that the IESO modify the RT-GCG program such that the revenues that are used to offset guaranteed costs under the program are expanded to include any profit (revenues less incremental operating costs) earned (a) on output above a generation facility's minimum loading point during its minimum generation block run time (MGBRT), and (b) on output generated after the end of the facility's MGBRT.
January 6, 2014	3-3	The Panel recommends that the IESO re-examine the question of integrating exports into EDAC to reduce the need to commit additional generation in real-time to meet export demand that currently only appears in the market in real-time. While the Panel is not recommending a specific approach for integrating exports, the following have been identified as potential options: (a) introduce a mechanism that encourages exports to bid in EDAC; or (b) include a forecast of exports when commitments are made under EDAC.
October 8, 2015	2-1	The Panel recommends that the IESO assess the methodology used to set the intertie zonal price for a congested intertie when the Net Interchange Scheduling Limit is binding or violated, in order to make the incentives provided by the intertie zonal price better fit the needs of the market.
November 17, 2016	2-1	Given the number of recent changes in the Operating Reserve market, the Panel recommends that the IESO review whether the real-time Operating Reserve prices transparently reflect the value of Operating Reserve as more Control Action Operating Reserve (CAOR) capacity is scheduled, and whether changes to Control Action Operating Reserve offer quantities and prices could enhance the efficiency of the Operating Reserve market.
November 17, 2016	3-1	The Panel recommends that the IESO eliminate from the Real-time Generation Cost Guarantee program the guarantees associated with: (a) incremental operating costs for start-up and ramp to minimum loading point; and (b) incremental maintenance costs for start-up and ramp to minimum loading point.
November 17, 2016	3-2	The Panel recommends that the IESO modify the Real-time Generation Cost Guarantee program such that the revenues that are used to offset guaranteed costs under the program are expanded to include any net energy and Operating Reserve revenues earned, as well as all congestion management settlement credit payments received, on: (a) output above a generation facility's minimum loading point during its minimum generation block run time (MGBRT), and (b) output generated after the end of the facility's MGBRT.

Report Issuance Date	Rec. No.	Recommendation
May 8, 2017	3-2	The IESO should revise the methodology used to set the intertie failure charge to include the congestion rents that an intertie trader avoids when it fails a scheduled transaction for reasons within its control.
December 19, 2019	2-1	The IESO should consider ways and means of deterring the Intertie Operating Reserve nodal price chasing behaviour described in this report.
December 17, 2020	2-1	The IESO should eliminate the payment for start-up costs for second and subsequent RT-GCG runs in a day. Alternatively, when a generation unit has participated in the RT-GCG program once during a day, the IESO should consider ways to have the generation unit compensated on the basis of the lesser of the second and subsequent submitted start-up costs or the estimated cost of keeping the generation unit online between RT-GCG runs.
September 2, 2021	3-3	The IESO should immediately cease reimbursements to gas generators of carbon cost payments.
September 2, 2021	3-4	If the IESO insists on reimbursement of carbon cost payments, they should develop a methodology that preserves the incentives of the carbon price. Any reimbursement should amount to a small percentage of the carbon cost payments imposed by the carbon pricing system. Only facilities that have paid an annual carbon cost charge should qualify for the carbon cost reimbursement.

Exhibit “O”

OEB Market Surveillance Panel report dated May 2017

Exhibit “O”

to the Affidavit of Francois Tardif

Sworn before me on October 29, 2025, in accordance with O. Reg. 431/20, Administering Oath or Declaration Remotely



Commissioner for Taking Affidavits
(or as may be)

October 29, 2025

Keith Edward Hickey, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.

Expires June 24, 2027.

Ontario Energy Board **Commission de l'énergie de l'Ontario**

Ontario

Market Surveillance Panel

Monitoring Report on the IESO-Administered Electricity Markets

for the period from
November 2015 – April 2016

May 2017

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Role of the Market Surveillance Panel

The Market Surveillance Panel (Panel) is a panel of the Ontario Energy Board. Its role is to monitor, investigate and report on activities related to – and behaviour in – the wholesale electricity markets administered by the Independent Electricity System Operator (IESO).

The Panel monitors, evaluates and analyzes activities related to the IESO-administered markets and the conduct of market participants to identify:

- inappropriate or anomalous conduct in the markets, including gaming and the abuse of market power;
- activities of the IESO that may have an impact on market efficiencies or effective competition;
- actual or potential design or other flaws and inefficiencies in market rules and procedures; and
- actual or potential design or other flaws in the overall structure of the IESO-administered markets and assess consistency of that structure with the efficient and fair operation of a competitive market.

Market-related activities and market conduct may also be the subject of a more formal and targeted investigation by the Panel. To that end, the Panel has authority under the *Electricity Act, 1998* to compel testimony and the production of information.

The Panel reports on the results of its monitoring and investigations, making recommendations for remedial action as it considers appropriate.

Executive Summary

Market Overview and Developments

In Chapter 1 the Panel provides its general assessment of the state of the IESO-administered markets, including their efficiency and competitiveness. Given some of the limiting features of Ontario's hybrid market design, competitive market forces play a greatly diminished role relative to what was originally envisioned, as well as relative to other North American jurisdictions. There remain significant opportunities to unlock competition and drive more efficient production, delivery, consumption and investment decisions.

To that end, the Independent Electricity System Operator (IESO) launched the Market Renewal stakeholder engagement in March 2016. Engagement participants and the IESO are critically examining the foundations of Ontario's electricity market; in doing so, identifying current market design issues and considering fundamental changes.

The Panel strongly supports the IESO exploring market design alternatives and will continue to support the initiative through its participation in the Market Renewal stakeholder initiatives.

In addition to Market Renewal, the Panel provides brief updates on a number of IESO and broader industry initiatives, including: the expansion of the Industrial Conservation Initiative, Ontario's energy trade deal with Québec, the Province's Greenhouse Gas Cap and Trade program and the IESO's capacity export initiative.

In the Panel's November 2016 Monitoring Report it made two recommendations related to the Real-Time Generation Cost Guarantee (RT-GCG) program. In addition, the Panel made three submissions to the IESO's *RT-GCG Program Cost Recovery Framework* stakeholder engagement. In each case, the Panel stated its concern with the cost of the RT-GCG program, as well as its uncertain benefits. The Panel's own analysis demonstrated that the program was necessary less than 1% of the time it was used.

The IESO has yet to address these concerns in a meaningful way.

The Panel believes that a new approach is needed that balances the competing priorities of reliability and cost and ensures that decisions are supported by objective analysis that considers whether lower cost alternatives are feasible. To guard against a "reliability at all costs" approach,

other jurisdictions have developed objective and open processes for assessing these competing priorities. A similar approach should be considered in Ontario.

Matters to Report in the Ontario Electricity Marketplace

Assessment of the IESO's Demand Response Auction

Since 2004, the Government of Ontario has been mandating the development of electricity conservation programs. The primary aim of these programs is to alleviate the need to build new generation facilities by reducing demand during peak periods. Demand Response (DR) programs, which incent consumers to reduce consumption during periods of high prices, high demand or tight supply, have been a large part of that conservation effort.

The IESO is responsible for achieving the conservation related policy goals set forth by the Ministry of Energy. Prior to 2015, bilateral contracting was the primary means of procuring the necessary DR resources to meet policy objectives; in 2015, the IESO developed the DR auction. The DR auction introduced a competitive, flexible and transparent process for procuring DR resources, where formerly there was none. DR resources procured in the 2016 and 2017 DR auctions will be paid up to a total of $73 million; these payments are recovered from Ontario consumers by uplift charges.

The resources procured through the DR auction are intended to help meet the Ministry of Energy's conservation policy goals. However, for the reasons explained in detail in Chapter 4 of this Report, it is unlikely that the current DR program will actually contribute to conservation or demand reduction. Briefly, this is because the rules associated with the DR auction establish thresholds for activation which have not been realized to date and are unlikely to be realized in the future.

Having said that, the Panel also questions the need for peak shaving DR capacity at this time as Ontario has sufficient resources to meet peak demand in the province for the foreseeable future.

Recommendation 4-2:

The IESO should reassess the value provided by the capacity procured through its Demand Response auction in light of Ontario's surplus capacity conditions, as well as the stated

preference of the government and the IESO (through its Market Renewal initiative) for technology-neutral procurement at least cost.

Improving the Allocation of Disbursements from the Transmission Rights Clearing Account

When an intertie becomes congested, the price used to settle intertie transactions can differ from the province-wide Market Clearing Price (MCP). This produces a situation in which either side of the same transaction is settled at different prices: the intertie transaction is settled at the intertie price, while the corresponding domestic transaction is settled at the MCP. The difference in the money collected from the buyer and paid to the seller is referred to as congestion rent. Congestion rent reflects the value of scarce transmission capacity. The more valuable access to a transmission path is to those who wish to utilize it, the higher the congestion rent collected.

Given intertie traders are willing to pay for scarce transmission capacity in the form of congestion rent, it follows that the owner of transmission capacity would benefit from making that transmission capacity available. In Ontario, the companies that own transmission capacity are rate regulated. Any congestion rent revenue these companies receive would go to offset their revenue requirements, thus reducing the regulated rates charged to their transmission customers. It follows that transmission customers benefit from congestion rent.

Congestion introduces financial risk to intertie traders. In order to provide the opportunity to hedge against that risk, the IESO operates a Transmission Rights (TR) market. TRs provide a financial hedge against price differences between the intertie price and the MCP. TR payments are designed as a full hedge against paying congestion rents; accordingly, TR payments and congestion rents collected should be approximately equal. By purchasing a TR, the owner has essentially purchased the right to the congestion rents on that intertie.

In return for relinquishing congestion rents, transmission customers receive the proceeds generated from the sale of TRs; these proceeds are known as “auction revenues”. Auction revenues accrue in the TR Clearing Account and are periodically disbursed to transmission customers to offset the transmission charges they pay. The manner in which these funds are disbursed has no impact on market efficiency or reliability, therefore the Panel looked to its other mandated principle, namely fairness, to assess the appropriateness of the existing methodology.

Considering that disbursements are intended to offset transmission charges, they are effectively a rebate on costs paid. The Panel believes that a fair allocation would have each customer receive a rebate proportionate to its share of costs paid. Unfortunately the current allocation methodology has not resulted in what the Panel considers to be a fair allocation of disbursements. Ontario transmission customers have paid in excess of 98% of all transmission charges, but received only 86% of disbursements; exporters received 14% of disbursements despite paying less than 2% of total transmission charges.

This misalignment stems from the fact that disbursements are allocated based on each customer's share of demand over the previous months, not its share of transmission service charges paid. The transmission charge associated with a megawatt-hour of Ontario based demand is significantly higher than the transmission charge associated with a megawatt-hour of export demand. As a result, exporters benefit disproportionately when disbursements are based on demand.

To date, the IESO has disbursed $58 million from the TR Clearing Account to exporters, $51 million of which the Panel believes ought to have been paid to Ontario transmission customers. Given the ongoing and material nature of this issue, future transfers will be significant if the current disbursement allocation methodology is left unremedied.

Recommendation 4-1

A. ***The IESO should revise the manner in which it allocates disbursements from the Transmission Rights Clearing Account such that disbursements are proportionate to transmission service charges paid over the relevant accrual period.***
B. ***The IESO should not disburse any further funds from the Transmission Rights Clearing Account until such time that Recommendation 4-1(A) has been addressed.***

Market Outcomes and Anomalous Events

The Panel's review and analysis of market outcomes covers the period from November 2015 to April 2016 (the Current Reporting Period). The Panel's analysis revealed the following items of interest.

Dispatchable Loads and Unavailable Operating Reserves

Operating Reserve (OR) is standby capacity intended to respond and recover from a contingency on the grid, such as a forced generator or transmission outage. A dispatchable load (DL) may provide OR standby capacity; when it is activated to help recover from a contingency, the DL provides relief by reducing its consumption. To be able to provide the required relief (and fulfill its OR activation), a DL must be consuming at least the activation amount prior to being activated.

In Chapter 3, the Panel examines an hour in which two DLs got paid for OR they were technically incapable of providing. These resources were compensated $25,760 for 29 MWh of standby capacity, despite not consuming sufficient electricity to provide that OR if called upon. This outcome is inappropriate: not only were the DLs potentially compromising the reliability of the grid by operating in a manner which rendered them unable to meet their OR obligation, but they were compensated for such behaviour.

This unavailable OR issue is much larger than the aforementioned example: from January 2010 to April 2016, the Panel estimates that DLs received approximately $12.5 million in OR payments for reserves that they were incapable of providing. DLs scheduled for ten-minute OR were capable of providing the entirety of their OR schedule in only 9.6% of all intervals during the Current Reporting Period.

Recommendation 3-1

The IESO should take steps to ensure that dispatchable loads are only compensated for the amount of operating reserve they were capable of providing in real-time. More fundamentally, the IESO should explore options for ensuring unavailable OR is not scheduled in the first instance.

Ramp-Down CMSC Payments and Market Rule Implementation Constraints

A generator signals its intent to come offline at the end of its run by raising its energy offer price above the local nodal price, thus becoming uneconomic in the constrained sequence. Due to the three-times ramp rate assumption used in the unconstrained sequence, a generator's unconstrained schedule ramps down faster than its constrained schedule. As a result, there is a divergence between the two schedules during the ramp-down period, resulting in constrained-on

Congestion Management Settlement Credit (CMSC) payments. In Chapter 3, the Panel examines one such payment to a gas-fired generator, totalling $160,000 over the course of one hour.

In past reports, the Panel has highlighted the inappropriate nature of CMSC payments caused by ramping, and recommended that the IESO eliminate them; CMSC is not intended to provide a revenue stream for generators that take a voluntary action.

In response to the Panel's concerns, the IESO recommended and its Board of Directors approved a Market Rule amendment to mitigate the cost of CMSC payments caused by ramping. This amendment was approved in June 2015 contingent on implementation of necessary IT system changes. Due to the complexity of these changes, they were not implemented until December 2016. The Panel estimates that CMSC payments caused by ramping would have been reduced by $1.9 million had the rule changes been effective immediately upon approval. In the future, the Panel suggests that the IESO consider providing for retrospective application of such changes to the date they are approved.

Export Failures and Congestion Rent Shortfalls

When an intertie is congested and a transaction fails following the final pre-dispatch run, the congestion rent collected may not be sufficient to cover the TR payments made, resulting in congestion rent shortfall.[1] Congestion rent shortfall results in a transfer of funds from Ontario consumers to TR owners, who are often intertie traders themselves.

When an intertie trader fails a transaction for reasons within its control (such as failing to acquire the proper transmission), it may be levied an intertie failure charge. The current intertie failure charge fails to account for the congestion rent shortfall created by the failure, leaving Ontario consumers to pay for the shortfall. This outcome is clearly inappropriate.

In Chapter 3, the Panel examines a day in which an intertie trader failed 7,456 MWh worth of exports, all for reasons within its control. For these failures, the intertie trader was charged a $466 intertie failure charge, despite causing over $12,000 in congestion rent shortfalls. This same

[1] For a quick overview of congestion rent and TRs, see the *Improving the Allocation of Disbursements from the Transmission Rights Clearing Account* section of the Executive Summary.

intertie trader profited from these intentional failures due to the TRs it owned, netting over $14,000 in TR payments.

The congestion rent shortfall issue is much larger than the aforementioned example: from January 2010 to April 2016, the Panel estimates that intertie failures within the control of market participants have resulted in congestion rent shortfalls of approximately $11 million.

Recommendation 3-2:

The IESO should revise the methodology used to set the intertie failure charge to include the congestion rents that an intertie trader avoids when it fails a scheduled transaction for reasons within its control.

Demand and Supply Conditions

Due to the mild winter weather, demand was down for all months of the Current Reporting Period relative to the same months from the previous year.

On the supply side, approximately 550 MW of nameplate generating capacity was added to the IESO-controlled grid during the Current Reporting Period. The new generating stations were all from renewable fuel sources, including 400 MW of wind capacity and 100 MW of solar capacity. Over the same period, 130 MW of distribution connected generating capacity was added, the majority of which was solar generation.

Market Prices and Effective Electricity Prices

The average Hourly Ontario Energy Price was less than $10/MWh during the Current Reporting Period, the lowest average of any six month period since market opening. Approximately one third of all hours during the Current Reporting Period experienced a price of $0/MWh or less.

Despite the low market prices, the average effective electricity price remained stable at $60.07/MWh for Direct Class A consumers, and increased $7.48/MWh to $112.25/MWh for Class B and Embedded Class A consumers. The higher average effective electricity prices for Class B and Embedded Class A consumers reflects an increase in Global Adjustment (GA) payments made to contracted and regulated resources. In January 2016 monthly total system costs, which reflects the effective electricity prices paid by all classes of consumers combined, reached an all-time high of just over $1.2 billion.

Chapter 1: Market Overview and Developments

1 *General Assessment*

Once annually, the Panel is required to provide a general assessment of the state of the IESO-administered markets, including their efficiency and competitiveness.

Since market opening in 2002, and particularly since the advent of the hybrid market in 2005, the Panel has assessed the state of the markets with regard to several design features and policy decisions that affect market participant behaviour and market outcomes. As noted frequently in past Panel reports, these features include:

- Ontario's two-schedule pricing and dispatch system: under this system, the prices faced by wholesale market participants can diverge (sometimes significantly) from the incremental cost of supplying another megawatt of energy at a particular location.
- Investment decisions are not driven by market dynamics: virtually all generation in Ontario is subject to long-term contracts with government agencies, or rate regulation by the Ontario Energy Board. Additionally, incentives under the contracts and regulation can result in offer prices that deviate from the generators' short-run marginal cost.
- The 3-times ramp rate multiplier: the use of the multiplier in the unconstrained sequence artificially depresses the market clearing price and distorts production and consumption decisions.

At market opening, some of the aforementioned features and impacts were expected to be temporary, while others were never envisioned at all; all have persisted over a number of years. The Panel has a long history of reporting on the systemic issues associated with these features, including: extended periods of deeply negative prices, inefficient trade on the interties and inappropriate wealth transfers.

Though the Panel has been critical of these features, it recognized them as ingrained parts of the current market design. In that context, the Panel's past assessments of the competitiveness and efficiency of the IESO-administered markets have been made with regard to the inherent limitations created by those features. In other words, the Panel made its assessments "within the Ontario context". On that limited basis, the Panel has said that the IESO-administered markets operated in a reasonably satisfactory manner.

Stepping out of the Ontario context, it is clear that competitive market forces play a greatly diminished role relative to what was originally envisioned, as well as relative to other North American jurisdictions. There remain significant avenues to unlock competition and drive more efficient production, consumption and investment decisions.

The IESO acknowledges the deficiencies in the current system and recognizes the benefits that market reform could bring to the sector. To that end, the IESO launched the Market Renewal stakeholder engagement in March 2016. Engagement participants and the IESO are critically examining the foundations of Ontario's electricity market; in doing so, identifying current market design issues and considering fundamental changes.

The IESO's Market Renewal initiative represents a significant opportunity to address many of the issues identified by the Panel over the years. Broad market reform has the potential to foster competition in existing markets, while introducing new competitive markets and mechanisms; all with the goal of improving efficiency. Market reform may include: the replacement of the two-schedule system with locational marginal pricing, a financially binding day-ahead market, unit commitment using multi-hour optimization, more frequent intertie scheduling and competitive procurement through technology neutral capacity auctions.

The Panel strongly supports the IESO exploring these market design alternatives and will continue to support the initiative through its participation in the Market Renewal stakeholder engagement process.

While important change is on the horizon, both the Panel and IESO recognize the long timelines associated with implementing Market Renewal. Between now and the completion of the initiative, the Panel will continue to identify deficiencies in the current market design and market rules that impact the efficient and fair operation of competitive markets. In cases where the impacts are too costly to go unaddressed until Market Renewal, or where Market Renewal will not address the issue, the Panel will continue to recommend expeditious changes, as it has done in this report.

2 *Future Development of the Market*

The IESO is currently undertaking a number of significant initiatives; they are discussed in the sections that follow.

Market Renewal

As discussed in the *General Assessment* section above, the IESO launched its Market Renewal stakeholder engagement initiative in March 2016. This initiative allows the IESO and stakeholders to address known challenges with the existing market design, and create a foundation for a more dynamic energy market to meet future needs.

The initiative will consider fundamental design changes in three categories: energy production and scheduling, capacity and operability. Specifically, the IESO has proposed the following projects in the Market Renewal work plan:

- Two schedule replacement - moving to a pricing approach reflective of actual costs
- Day-ahead market - introducing a day-ahead market to provide greater certainty to market participants and the IESO
- Real-time unit commitment - improving real-time unit commitment to optimize supply and demand over multiple hours with known costs
- Interties - enhancing intertie scheduling to improve efficiency and flexibility
- Demand response auction – establishing a workable and useful demand response auction
- Capacity trade - develop a system to enable the sale of capacity to other jurisdictions
- Capacity auction - develop an auction for incremental capacity needs.

In pursuit of these proposed changes, the IESO has retained the Brattle Group to complete a benefits case for Market Renewal. In the interim, the IESO presented the preliminary findings of its benefits case at its December 19, 2016 stakeholder engagement meeting. The preliminary findings suggest that the efficiency benefits of Market Renewal would be significant: approximately $3.7 billion from 2021 through 2030; with consumers benefitting $3.1 billion. These benefits far exceed expected implementation costs of $155 million. The final report summarizing the findings of the benefits case is expected to be published by the end of Q1 2017.

Expansion of the Industrial Conservation Initiative

On January 1, 2017 the Ontario Government expanded the Industrial Conservation Initiative (ICI) to allow customers with peak demand exceeding 1 MW to opt into the program. When introduced in 2010, only customers with peak demand greater than 5 MW were eligible to participate; the eligibility criteria was first reduced to 3 MW in 2015.

ICI customers' share of Global Adjustment charges varies based on their consumption during the five coincident peak demand hours during a year. The expansion of the ICI program will most likely mean higher Global Adjustment charges for lower volume customers, as more ICI customers shift consumption to avoid Global Adjustment charges.

Energy Trade Agreement with Québec

The provincial governments of Ontario and Québec recently signed a seven year energy trade agreement running from 2017 through 2023.[2] The general structure of the agreement includes the following elements:

- Québec will provide Ontario with 2 TWh of electricity each year,
- Ontario will reserve 500 MW of generating capacity to meet Québec's winter peak demand, and
- Ontario may provide electricity to Québec during times of surplus, part of which gets returned to Ontario during non-surplus hours.

The Panel will monitor for the impacts of the agreement on trade flows and efficiency in Ontario's wholesale electricity market.

Greenhouse Gas Cap and Trade Program

Effective January 1, 2017, greenhouse gas emitters from the energy sector are subject to the Government of Ontario's new cap and trade program. Participants in the program must have enough emission allowances to cover their emissions by the end of each compliance period. Emission allowances can be purchased at one of the quarterly auctions, or on the secondary market.[3]

Among Ontario's greenhouse gas emitters is its fleet of natural gas-fired generators. Unlike most emitters under the program, natural gas-fired generators supplied by an Ontario Energy Board (OEB) regulated gas distributor will not be obligated to acquire emissions allowances directly. Instead, the natural gas distributor will be responsible for acquiring the necessary emission allowances and complying with the program. The cost of purchasing the allowances will be

[2] For more information see the Government of Ontario's backgrounder, available at: https://news.ontario.ca/opo/en/2016/10/agreement-between-the-government-of-ontario-and-the-gouvernement-du-quebec-concerning-electricity html

[3] For an overview of Ontario's greenhouse gas cap and trade program, see the Government of Ontario's webpage, available at: https://www.ontario.ca/page/cap-and-trade-ontario. Ontario Regulation 144/16, which passed the cap and trade program into law, is available at: https://www.ontario.ca/laws/regulation/r16144?_ga=1.105770058.816112800.1484255410

passed along to the emitters themselves, the natural gas-fired generators, in the form of a volumetric charge on natural gas purchased.[4]

The Panel expects this new volumetric charge to be included in the incremental energy offers of natural gas-fired generators. It follows that, when one of these generators is the marginal unit setting the Market Clearing Price (which was the case 19% of the time in 2016), the price will be higher. An increase in the MCP will have numerous impacts throughout the market, most notably on intertie flows and the proportion of the all-in cost of electricity recovered through the market versus the Global Adjustment.[5]

Imports from jurisdictions that typically have greenhouse gas emitting technologies on the margin are now subject to the cap and trade program. Importers will need to purchase emission allowances based on the quantity of imports and the Default Emission Factor (DEF) that applies to the source jurisdiction. Jurisdictions with heavily emitting supply mixes face higher DEFs and therefore must purchase more allowances for the same import quantity. To that end, imports from PJM, NYISO, ISO-NE and MISO will be subject to positive DEFs, while imports from Manitoba and Québec, which are primarily backed by hydroelectric generation, will not.[6] This has the effect of decreasing the competitiveness of imports from high emitting jurisdictions, while increasing the competitiveness of imports from cleaner ones.

The Panel will continue to monitor for the impacts of the cap and trade program on Ontario's wholesale electricity market.

Capacity Exports

In February 2015 the IESO launched its *Capacity Exports* stakeholder engagement to investigate the potential for allowing Ontario generators to export their capacity to other jurisdictions.[7]

[4] See the OEB's *Regulatory Framework for the Assessment of Costs of Natural Gas Utilities' Cap and Trade Activities* report, page 30, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2015-0363/Report_Cap_and_Trade_Framework_20160926.pdf
[5] Generally, the MCP and the Global Adjustment are inversely related, meaning when one increases the other tends to decrease, and vice versa.
[6] The DEFs are posted on the Government of Ontario's webpage, available at: http://www.energy.gov.on.ca/en/ontarios-electricity-system/climate-change/
[7] For more information see the IESO's *Capacity Exports* stakeholder engagement webpage, available at: http://www.ieso.ca/sector-participants/engagement-initiatives/engagements/capacity-exports

By facilitating the export of generating capacity that is not needed for reliability in Ontario, the IESO is providing an opportunity for participants to monetize capacity that would otherwise go idle or decommission. This additional revenue stream for generators could also benefit Ontario consumers: if the exporting generator has an Ontario supply contract or is subject to rate regulation, some of the additional capacity revenues would go to offset payments under those frameworks.

As part of the engagement process, market participants were asked to contact the IESO to discuss specific export opportunities of interest. While there was general interest in capacity export opportunities to New York and Québec, only one stakeholder expressed a strong interest in pursuing a specific near term project, and demonstrated readiness. The IESO successfully implemented the necessary procedures and agreements, allowing the aforementioned market participant to offer its capacity into the New York 2016-2017 winter capacity auction.

In the longer term, the IESO intends to incorporate the capacity export initiative in to Market Renewal. In doing so, the IESO is looking to evolve capacity export opportunities by adding additional export markets, automating the participation process and integrating capacity exports into the planned incremental capacity auction in Ontario.

3 *IESO Responses to Most Recent Panel Recommendations*

Recommendation	IESO Response
Recommendation 2-1 *Given the number of recent changes in the operating reserve market, the Panel recommends that the IESO review whether the real-time operating reserve prices transparently reflect the value of operating reserve as more Control Action Operating Reserve capacity is scheduled, and whether changes to Control Action Operating Reserve offer quantities and prices could enhance the efficiency of the operating reserve market.*	The IESO will undertake the recommended review in the new year to assess the issues with the current CAOR structure and identify potential options. I anticipate that IESO staff will complete the review and report back to the MSP by late Q1 2017.

Recommendation	IESO Response
Recommendation 3-1 *The Panel recommends that the IESO eliminate from the Real-time Generation Cost Guarantee program the guarantee associated with:* *a) incremental operating costs for start-up and ramp to minimum loading point; and* *b) incremental maintenance costs for start-up and ramp to minimum loading point.*	Background Mandatory North American reliability standards require that the IESO's daily Operating Plan demonstrate that adequate resources will be available to meet the expected load plus operating reserve. The RT-GCG program is a key element of the mechanisms that the IESO relies on in developing its daily Operating Plan and preparing for reliable real-time operations. In particular, the RT-GCG program helps meet daily reliability requirements by incenting participants to start their facilities, be available and offer real-time supply to the market. The incentive is available for generation facilities that meet eligibility criteria to ensure recovery of certain incremental start-up costs, subject to defined revenue offsets. As noted, the primary goal of the IESO's RT-GCG program is to ensure that generators are available when needed. The IESO is concerned that the Panel's recommendations, which would significantly reduce the incentive structure under the program, could have negative impacts on the program's overall reliability goals, in that the output from some gas-fired units might not be offered into the market in real time, which would, in turn, impact market dynamics and reliability, potentially impairing the IESO's ability to address changing conditions over the day. The Panel's recommendation to eliminate guarantees under the RT-GCG program for incremental operating and maintenance costs is based in part on earlier versions of the program where eligible payments were limited to fuel-only costs. However, at the time those earlier versions relied heavily on flexible generation to provide the vast majority of the starts under the program (about 80% of starts - of which over half were coal). By 2009, coal fired generation was being replaced by natural gas-fired generation facilities, which have very different operating characteristics and risk profiles. This change in the underlying characteristics of the supply mix was amongst the factors that prompted the IESO to make changes to the RT-GCG program, to include the guarantee of certain start-up operating and maintenance (O&M) costs, impose more stringent program eligibility criteria, and place limitations on eligible fuel costs - all aimed at improving the overall efficiency of the commitments. Proposed Improvements to the Commitment Process Given our concerns regarding the potential impact of the MSP recommendations, the IESO is proposing interim adjustments to the processes around unit commitments pending the market renewal initiative outlined below. These proposed changes would ensure that resources scheduled to provide Operating Reserve (OR) in the day-ahead timeframe continue to offer this OR in real-time. Currently some resources that are anticipated to provide OR based on day-ahead optimization withdraw their offers for OR closer to real-time. This
Recommendation 3-2 *The Panel recommends that the IESO modify the Real-time Generation Cost Guarantee program such that the revenues that are used to offset guaranteed costs under the program are expanded to include any net energy and operating reserve revenues earned, as well as all Congestion Management Settlement Credit payments received, on:* *a) output above a generation facility's minimum loading point during its minimum generation block run time (MGBRT), and* *b) output generated after the end of the facility's MGBRT.*	

	results in the IESO having to commit additional units in real time, many under the RT-GCG, to meet OR requirements. Introducing a mechanism to maintain scheduled OR offers from Day-Ahead into real-time should result in resources with limited real-time OR capability reducing the quantity they offer into the DACP, giving more confidence that the remaining quantities will in fact be available in real-time. This should result in the necessary units needed for OR to be committed more efficiently through the DACP, instead of through the RT-GCG Program. At the same time, the changes proposed in the current RT-GCG Cost Recovery Framework stakeholder engagement initiative will limit the initial O&M payments referenced in the Panel report by introducing pre-approved cost values that will ensure greater clarity and transparency in the recovery of eligible costs, and reduce the need for time consuming after-the-fact audits and recovery of ineligible costs. To date, these recoveries have amounted to about 25% of the initial amounts claimed under the program. The IESO expects that the proposed interim improvements to the commitment process can be implemented in 2017, recognizing that they will need to be formally reviewed under the IESO's stakeholder engagement processes. <u>Market Renewal</u> The MSP work, both on GCG and other issues, has driven increased focus on the need for market renewal. Simply put, the market design developed in the early 2000's needs to be modernized to support the very different technologies, services and participants in our fast-changing sector. Accordingly, in considering the balance between investing key resources in our current market (for example in working through major changes to programs such as GCG) or in renewing our market design to meet pressing current and future needs, our market renewal program is being given priority. The Market Renewal Program will introduce fundamental changes to the energy market, including a re-design of its real-time unit commitment process to achieve reliability objectives in a more efficient manner. Consistent with the feedback that the IESO received from the Panel, all the energy initiatives (Single Schedule, Day-Ahead Market and enhanced real-time unit commitment process) will be undertaken as a single cohesive project rather than as sequenced projects, as originally proposed. That approach will ensure earlier implementation of all components. Market renewal will be a significant project for the sector and we are looking forward to working with the MSP as it proceeds.

4 *Panel Commentary on IESO Response*

The IESO's response to the Panel's concerns about the cost and uncertain benefits of the RT-GCG program largely ignores the substance of those concerns. This is consistent with the IESO's reaction to the Panel's previous recommendations and its submissions to the IESO's recent stakeholder engagement on this subject. The IESO has largely adopted a "reliability at any cost" approach notwithstanding that the Panel's own analysis demonstrated that the program was actually needed in less than 1% of the time it was used.

The Panel continues to believe that an objective and rigorous cost/benefit analysis that considers the feasibility of less costly alternatives is required.

Other jurisdictions have developed processes for assessing the competing priorities of reliability and cost.[8] The Panel believes a similar approach should be considered in Ontario.

The IESO has proposed interim adjustments to the scheduling of operating reserve that could, if adopted, reduce the number of RT-GCG commitments. This would be a positive step. However, it does not account for the fact that RT-GCG commitments are largely driven by export demand, not operating reserve requirements.

Recommendation from the Panel's February 2015 Investigation Report

In late August 2010, the IESO passed an Urgent Market Rule Amendment to suspend all Congestion Management Settlement Credit (CMSC) payments to constrained-off dispatchable loads. These CMSC payments were suspended because significant amounts had been paid to two dispatchable loads; payments the IESO believed to be inconsistent with the intent of the CMSC regime. Following stakeholder consultation, the suspension of these payments was lifted, replaced by targeted Market Rules that withheld CMSC when specific behaviours were observed.

[8] A recent example involves the National Electricity Market in Australia where, following a period of unprecedented power disruptions in the state of South Australia, including a state-wide blackout, the South Australian government proposed market rule changes to enhance reliability. The Australian Energy Market Commission, the agency responsible for making rule changes, recognized that the proposed reliability enhancements will support security of supply for consumers but that they must also be delivered at the lowest possible cost. Even with the sector in a state of heightened concern over reliable supply, the passing of the proposed reliability enhancements remain subject to a robust cost benefit process. See: http://www.aemc.gov.au/Rule-Changes/Emergency-frequency-control-schemes-for-excess-gen#

In the course of its investigation into the possible gaming behaviour of the two aforementioned dispatchable loads, the Panel observed that despite the new Market Rules, significant CMSC continued to be paid.[9] The Panel recommended that the IESO review the CMSC payments being made to dispatchable loads, and if necessary, make further amendments to eliminate unwarranted CMSC payments.

The IESO conducted the recommended review and found what the Panel considers to be a material amount of unwarranted CMSC still being paid. While the IESO believes it has the appropriate authority under the Market Rules to address these CMSC payments,[10] its settlement processes do not prevent or recover these payments. The Panel encourages the IESO to implement the necessary changes to prevent or recover these unwarranted payments.

[9] For more information see the Panel's *Report on an Investigation into Possible Gaming Behaviour Related to Congestion Management Settlement Credit Payments by Abitibi-Consolidated Company of Canada and Bowater Canadian Forest Products Inc.*, available at:
http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Investigation_Report_CMSC_Abitibi_Bowater_2015.pdf
[10] See the IESO's response to the recommendation contained in the Panel's investigation report, available at:
http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/IESO_Reply_to_OEB_MSP_20150918.pdf

Chapter 2: Market Outcomes

This chapter reports on outcomes in the IESO-administered markets for the period between November 1, 2015 and April 30, 2016 ("Current Reporting Period"), with comparisons to the period between May 1, 2015 and October 31, 2015 ("Previous Reporting Period"), as well as other periods where relevant.

1 *Pricing*

This section summarizes pricing in the IESO-administered markets, including the Hourly Ontario Energy Price (HOEP), the effective price (including the Global Adjustment (GA) and uplift charges), operating reserve (OR) prices, and Transmission Rights (TR) auction prices.

Table 2-1: Average Effective Electricity Price by Consumer Class
May 2015 – October 2015 & November 2015 – April 2016
($/MWh)

Description:

Table 2-1 summarizes the average effective electricity price[11] in dollars per megawatt hour by consumer class for the Current Reporting Period and the Previous Reporting Period. The effective electricity price is the sum of the average load-weighted HOEP, the GA, and uplift charges. Results are reported for three consumer groups: "Direct Class A consumers" (Class A consumers that are directly connected to the IESO-controlled grid); "Class B & Embedded Class A consumers" (Embedded Class A consumers being Class A consumers that are connected at the distribution level);[12] and "All Consumers", which represents what the effective electricity price would have been for all consumers but for the change in the methodology for allocating the GA that took effect in January 2011. Information pertaining to Embedded Class A consumers is aggregated with information pertaining to Class B consumers because information regarding hourly consumption by Embedded Class A consumers is not readily available. Accordingly, effective price information pertaining to Class A consumers relates only to Direct Class A consumers.

[11] This price reflects the commodity cost of electricity and does not include delivery, regulatory, and debt retirement charges.
[12] Although the Panel does not have visibility over the data, it is reasonable to assume that Embedded Class A consumers likely pay an effective electricity price similar to Direct Class A consumers. Therefore, aggregating Class B consumers and Embedded Class A consumers within a single price category likely understates the effective electricity price for Class B consumers and likely overstates the effective electricity price for Embedded Class A consumers.

Customer Class	Weighted HOEP	Average Global Adjustment	Average Uplift	Effective Price
Direct Class A - Current	10.12	48.38	1.57	60.07
Direct Class A - Previous	21.07	36.53	2.40	60.00
Class B & Embedded Class A - Current	11.15	99.47	1.63	112.25
Class B & Embedded Class A - Previous	22.76	79.53	2.48	104.77
All Consumers - Current	11.03	93.28	1.62	105.93
All Consumers - Previous	22.56	74.38	2.47	99.41

*All references to "Current" in tables and figures in this report mean the Current Reporting Period. Similarly, all references to "Previous" mean the Previous Reporting Period.

Relevance:

In Ontario, different consumer classes pay different effective electricity prices. Consumers are divided into two groups: Class A—consumers with an average peak demand above 3 MW; [13,14] and Class B—all other consumers (including, for example, all small commercial and residential consumers).[15]

Many Class B consumers—those that use less than 250,000 kWh of electricity per year are and some others—are eligible for the Regulated Price Plan ("RPP") prices set by the Ontario Energy Board ("OEB"). They pay the RPP price unless they choose to enter into a contract with an electricity retailer (in which case they pay the contract price) or they choose to opt out of the RPP. The commodity price payable by Class B consumers that are not eligible for the RPP or that opt out of the RPP depends on their meter. If they have an interval meter, they pay the HOEP. If they do not have an interval meter, they pay a weighted average HOEP based on the net system load profile in their distributor's service area. For consumers that are not on the RPP or that have signed up with a retailer the GA appears as a separate line item on their electricity bill. Since RPP prices include a forecast of the GA, the GA is not a separate item on RPP consumer bills.

[13] Effective July 1, 2015, the government of Ontario expanded the definition of Class A from consumers with a peak demand of 5 MW or greater to include a subset of consumers with a peak demand greater than 3 MW but less than or equal to 5 MW. See IESO's Industrial Conservation Initiative Backgrounder, available at: http://iesoqa-public.sharepoint.com/Documents/Expansion%20of%20the%20ICI%20Backgrounder%20-%20June%202014%20(2).pdf .
[14] As the expansion of the Class A definition occurred mid-reporting period, a weighted average of the calculation was used for the Current Reporting Period results.
[15] See Ontario Regulation 429/04 (Adjustments under Section 25.33 of the Act) made under the *Electricity Act, 1998,* available at: http://www.ontario.ca/laws/regulation/040429.

For reference purposes, the table displays the average effective electricity price for "all consumers," which is calculated using the previous GA allocation methodology under which all consumers were allocated the GA based on their pro rata share of total consumption during the period. As of January 2011, the GA payable by Class A consumers is determined based on their peak demand factor, which is the ratio of the consumer's electricity consumption during the five peak hours[16] in a year relative to total consumption by all consumers in each of those hours. The GA continues to be charged to Class B consumers based on their total consumption during the period.[17]

In the Panel's April 2015 Monitoring Report,[18] the need to obtain generation and consumption data at an hourly level of granularity was discussed, specifically pertaining to embedded generation, behind-the-meter generation and embedded Class A consumers. While there is data on installed capacity of IESO-contracted embedded generation, the Panel noted that assessing the impacts of certain market changes is difficult, if not impossible, without generation and consumption data at the hourly level for these subsets of the Ontario electricity sector.

In a broader context, assessing the province's overall demand for electricity becomes increasingly difficult as a larger portion of that demand is no longer measured at the level of the high-voltage power system.

In particular, the Panel is interested in ascertaining the impacts of the GA allocation methodology on Class A consumption patterns for consumers that qualify for the Industrial Conservation Initiative ("ICI"). In order to more accurately calculate the effective commodity price for each consumer class in Ontario and quantify the impact of the ICI, access to hourly meter data for embedded Class A consumers and behind-the-meter generation is required. The Panel understands that the IESO is currently investigating means of collecting such information.

Commentary and Market Considerations:

[16] The five peak demand hours must occur on different days.
[17] For more information on the GA allocation methodology and its effect on each consumer class see the Panel's June 2013 Monitoring Report, pages 69-92, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2012-Oct2012_20130621.pdf
[18] For more information on this topic see the Panel's April 2015 Monitoring Report, pages 105-109, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2013-Apr2014_20150420.pdf

The average effective electricity price increased for both Direct Class A consumers and Class B & Embedded Class A consumers during the Current Reporting Period relative to the Previous Reporting Period. The GA was the primary driver behind increases in the effective electricity price, having increased for all consumers. The GA is primarily composed of payments to contracted and regulated generating resources that are intended to make up for shortfalls between market revenues and the contracted or regulated rates of those resources. As a consequence, the HOEP and the GA often exhibit an inverse relationship. This explains in part why the HOEP during the Current Reporting Period is less than half of what it was during the Previous Reporting Period.[19]

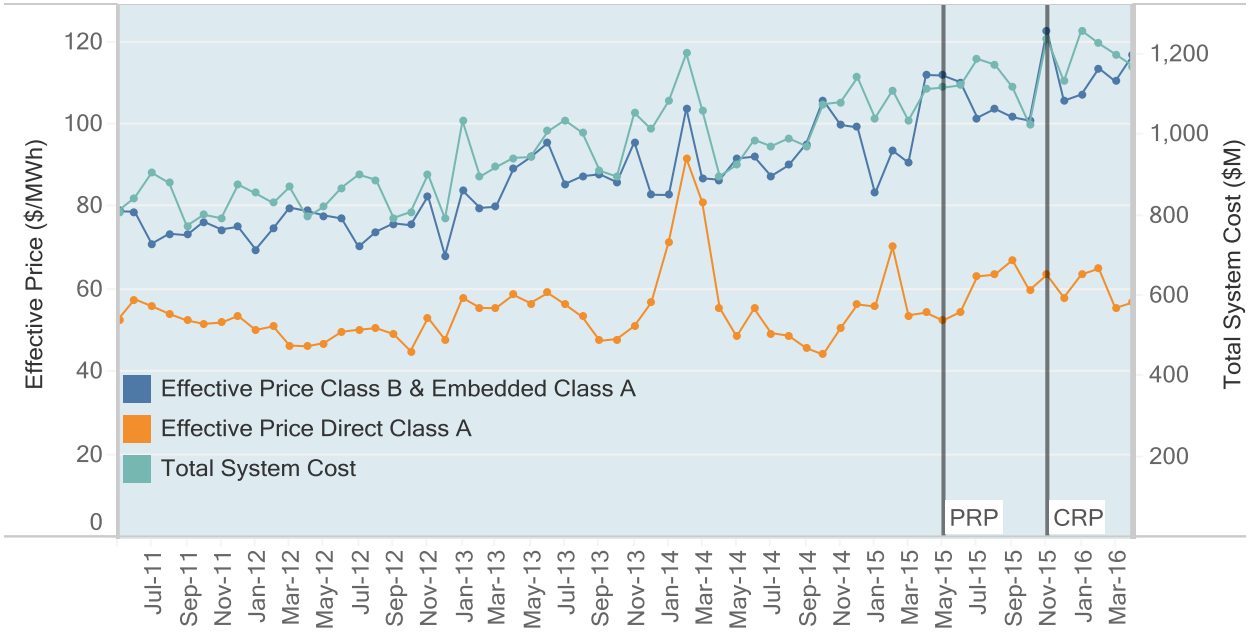
Direct Class A consumers saw the average GA increase by about $12/MWh while Class B & Embedded Class A consumers experienced an average GA increase of about $20/MWh. The average effective electricity price for both consumer classes was about $6/MWh greater in the Current Reporting Period than in the Previous Reporting Period.

Figure 2-1: Monthly Average Effective Electricity Price and System Costs May 2011 – April 2016 ($/MWh & $)

Description:

Figure 2-1 plots the monthly average effective electricity price for Direct Class A and Class B & Embedded Class A consumers, as well as the monthly average system cost (System Cost), for the previous five years.

[19] The costs associated with compensating loads under the IESO's demand response programs and administering various other conservation programs (such as the saveONenergy program) are also recovered through the GA. Additional information regarding the GA is available at: http://www.ieso.ca/sector-participants/settlements/global-adjustment-components-and-costs



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

This figure highlights the changes in the effective electricity price paid by each consumer class over the past five years, as well as the changes in System Cost.

Commentary and Market Considerations:

In the Current Reporting Period, there were both record high total System Costs (January 2016 at $1.17B) and record high average effective electricity prices (April 2016 at $116.64/MWh) for Class B & Embedded Class A consumers. Effective electricity prices for Direct Class A consumers were little changed.

Figures 2-2A & 2-2B: Average Effective Electricity Price by Consumer Class and by Component

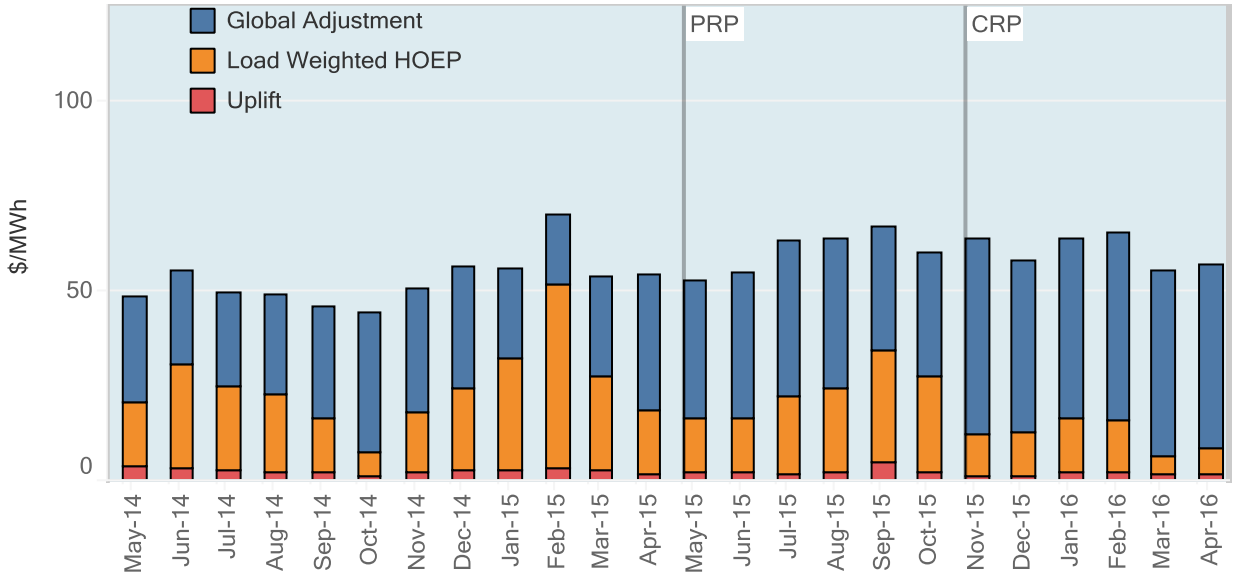
Description:

Figures 2-2A and 2-2B divide the monthly average effective electricity price into its three components (average HOEP, average GA, and average uplift charges) for Direct Class A consumers and Class B & Embedded Class A consumers for the previous two years.

As noted previously, the GA and the HOEP have an inverse relationship: when the HOEP decreases, the GA increases. The GA allocation methodology and the extent to which Class A

consumers respond to that methodology are responsible for the significant difference in the average effective electricity price paid by each consumer group. As the GA is charged to Class A consumers based on their share of peak load during the five hours with the highest total demand in a 12-month base period,[20] Class A consumers can substantially reduce or even eliminate their GA by reducing their consumption from the IESO-controlled grid during these hours. When the average GA makes up an increasing portion of System Cost the average effective price paid by Class B consumers increases proportionately more than that paid by Class A consumers. This relationship is readily apparent in the Current Reporting Period.

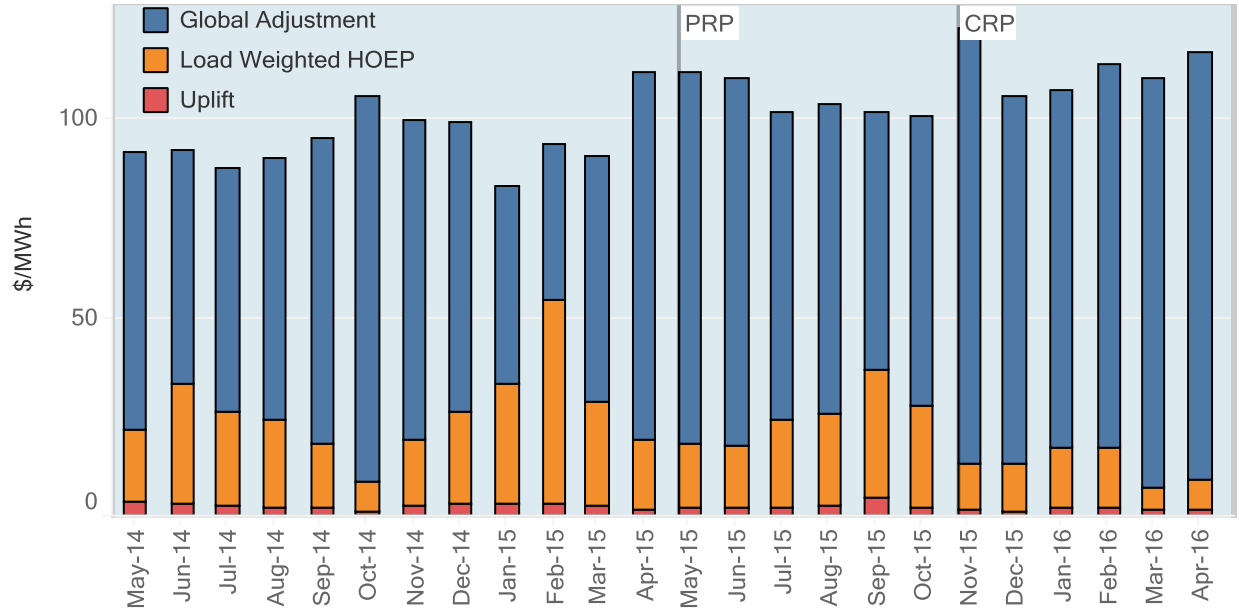
Figure 2-2a: Average Effective Electricity Price for Direct Class A Consumers by Component May 2014 – April 2016 ($/MWh)



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

[20] Each base period runs from May 1 in one year to April 30 in the following year. The GA allocation for the Current Reporting Period is based on the base period from May 2015 to April 2016.

Figure 2-2b: Average Effective Electricity Price for Class B & Embedded Class A Consumers by Component May 2014 – April 2016 ($/MWh)



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

These two figures illustrate how changes in the individual components of the effective electricity price affect the average effective electricity price paid by each consumer group.

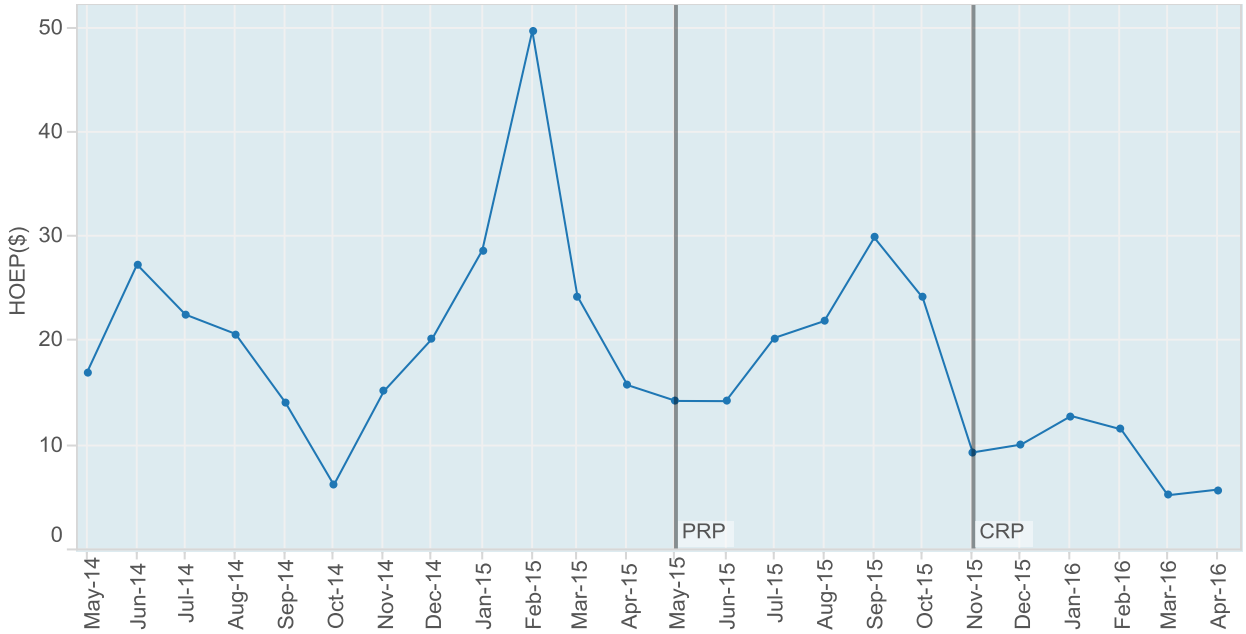
Commentary and Market Considerations:

The average effective electricity price for Class B & Embedded Class A consumers was significantly higher than that of Direct Class A consumers, as the former pay more GA compared to the latter. The GA also contributed to a record high share of the effective price in the Current Reporting Period.

Figure 2-3: Monthly (Simple) Average Hourly Ontario Energy Price (HOEP) May 2014 – April 2016 ($/MWh)

Description:

Figure 2-3 displays the simple monthly average HOEP for the previous two years.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

The HOEP is the market price for a given hour and is one component of the effective electricity price paid by consumers. The HOEP is the simple average of the twelve Market Clearing Prices ("MCP") within the hour and that are set every five minutes. The HOEP is paid directly by consumers who participate in the wholesale electricity market, and indirectly by consumers who pay the OEB's RPP.

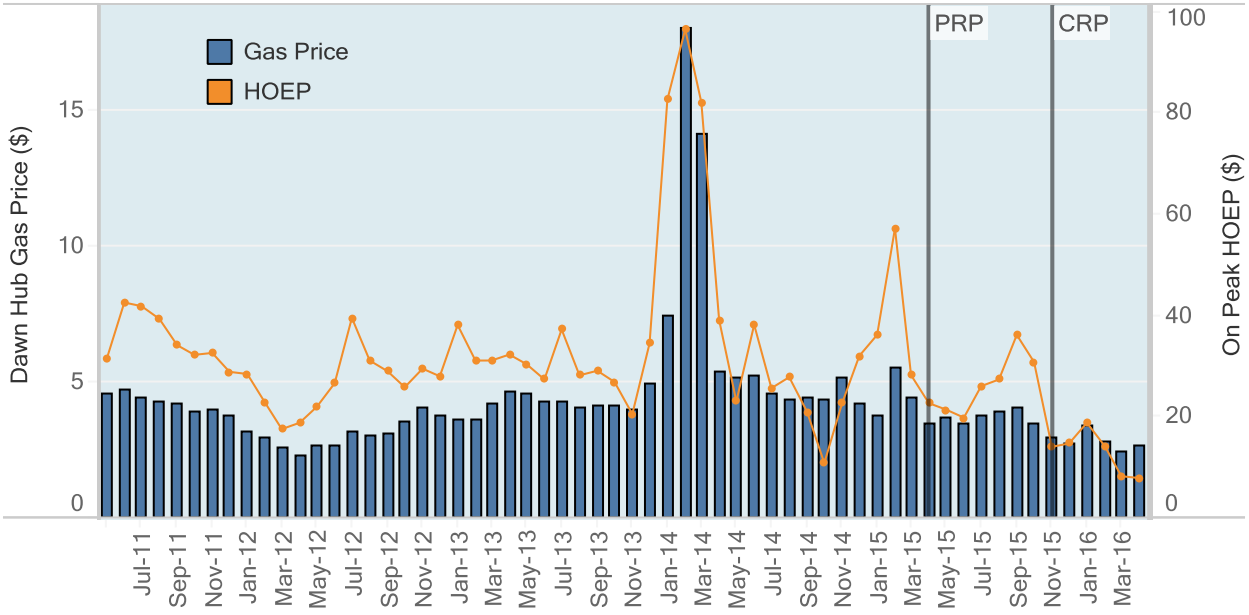
Commentary and Market Considerations:

The average HOEP of $9.09/MWh during the Current Reporting Period was significantly lower than that of both the Previous Reporting Period and the Winter 2015 Period: this is attributed to low demand and abundant supply, as nuclear units out of service in September 2015 and October 2015 were back online by the start of the Current Reporting Period and additional low marginal cost wind and solar capacity came online. The relatively low HOEP also reflects relatively low demand, owing to milder temperatures. Low demand also contributed to the Market Clearing Price ("MCP") often being set by resources offering at low prices such as wind, nuclear, and hydroelectric generation.

Figure 2-4: Natural Gas Price and On-peak Hourly Ontario Energy Price
June 2011 – April 2016
($/MWh & $/MMBtu)

Description:

Figure 2-4 plots the monthly average Dawn Hub day-ahead natural gas price and the average monthly HOEP during on-peak hours, for the previous five years.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

The Dawn Hub is the most active natural gas trading hub in Ontario and has the largest gas storage facility in the province. Gas-fired facilities can typically purchase gas day-ahead in order to ensure sufficient time to arrange for transportation; for that reason, the Dawn Hub day-ahead gas price is a relevant measure of the cost of natural gas in Ontario. Natural gas prices are compared to the HOEP during on-peak hours, as gas-fired facilities frequently set the price during these hours.

Commentary and Market Considerations:

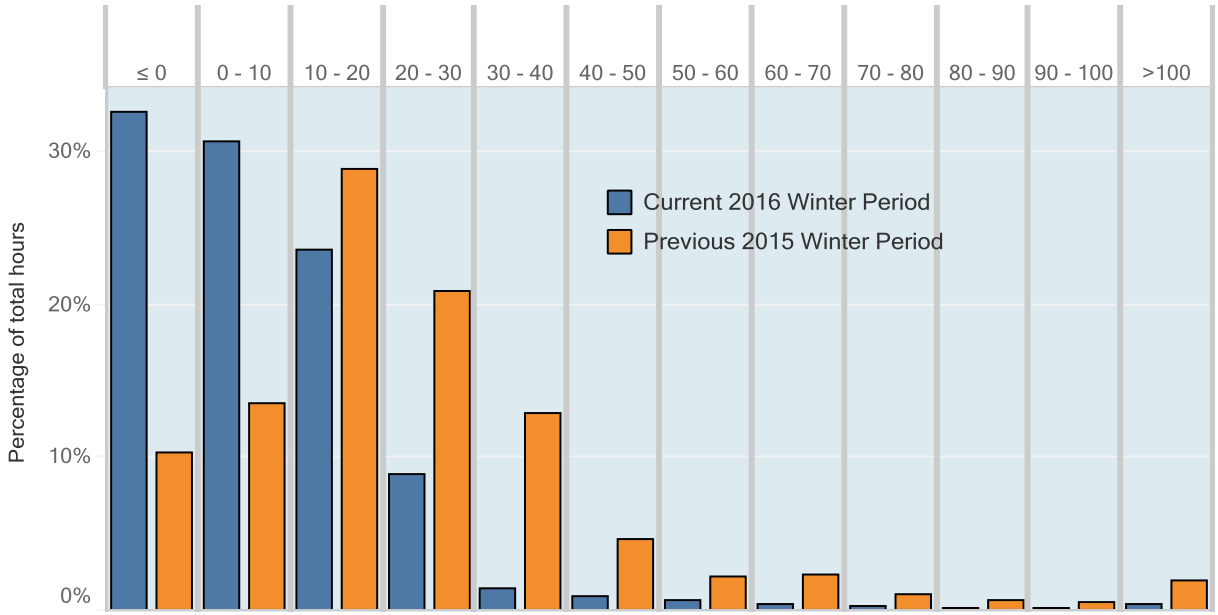
Dawn Hub gas prices have been declining since the Winter 2014 period: the Current Reporting Period had an average day-ahead gas price of $2.84/MMBtu, which was lower than that of the Previous Reporting Period at $3.72/MMBtu.

Daily changes in natural gas prices historically have been more strongly correlated with movements in the on-peak HOEP, with a correlation coefficient of 0.7069 for daily average prices from May 2011 to October 2015. The two prices have been weakly correlated in the Current Reporting Period, with a correlation coefficient of 0.3726. A contributing factor to the weak correlation is the lack of volatility in the daily average Dawn Hub gas price relative to the average on-peak HOEP.

Figure 2-5: Frequency Distribution of Hourly Ontario Energy Price
November 2014 – April 2015 & November 2015 – April 2016
(% of hours, $/MWh)

Description:

Figure 2-5 compares the frequency distribution of the HOEP as a percentage of total hours for the Current 2016 Winter Period (the same as the Current Reporting Period) and the Previous 2015 Winter Period (the same period from the previous year). The HOEP is grouped in $10/MWh increments; for example, the fourth price interval from the left counts all HOEPs greater than $20/MWh and less than or equal to $30/MWh. The negative-price hours are grouped together with all $0/MWh values in the category of HOEP less than or equal to $0/MWh.



Relevance:

The frequency distribution of the HOEP illustrates the proportion of hours that the HOEP falls into a given price range, providing information on the frequency of extremely high or low prices.

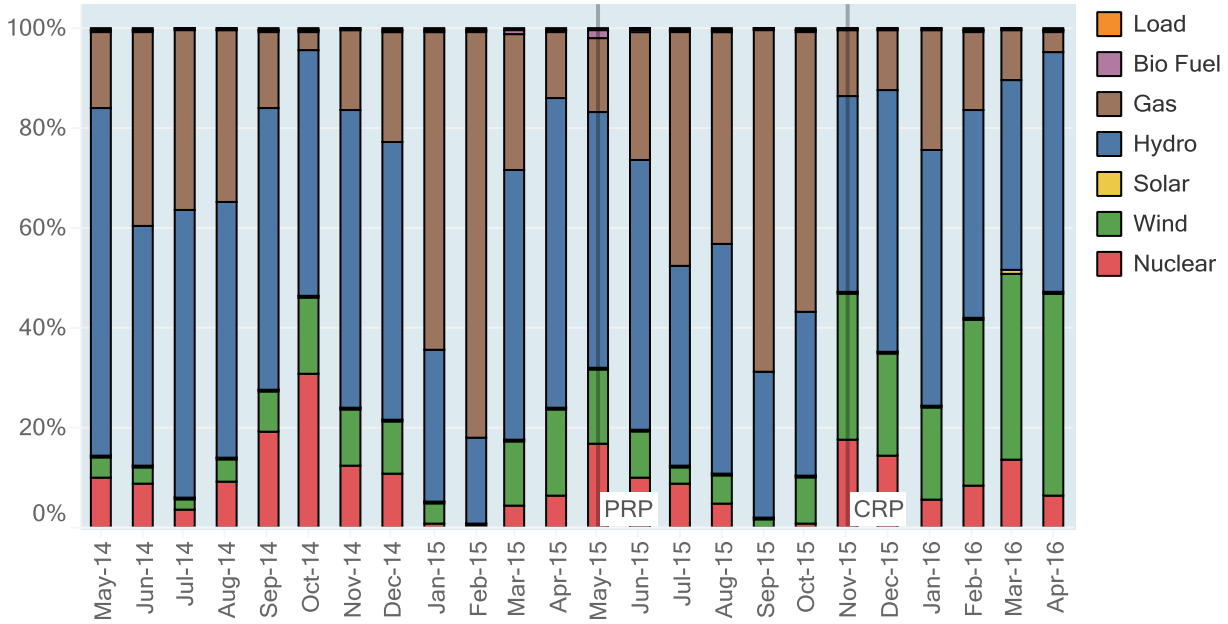
Commentary and Market Considerations:

The frequency distribution of prices illustrates a large increase in the amount of non-positive price hours (zero and negative) compared to the Winter 2015 Period. The HOEP was non-positive in 33% of hours in the Current Reporting Period. This is likely a result of the relatively low demand observed during the period, precipitated by mild weather conditions. The addition of approximately 400 MW of renewable energy capacity (which frequently offers at negative prices) was also a factor in causing lower prices. Chapter 2 examines the increase in non-positive price hours in greater detail.

Figure 2-6: Share of Resource Type setting Real-Time Market Clearing Price
May 2014 – April 2016
(% of intervals)

Description:

Figure 2-6 presents the monthly share of intervals in which each resource type set the real-time MCP, for the previous two years.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

The relative frequency of each resource type setting the real-time MCP is useful in understanding trends in the real-time MCP.

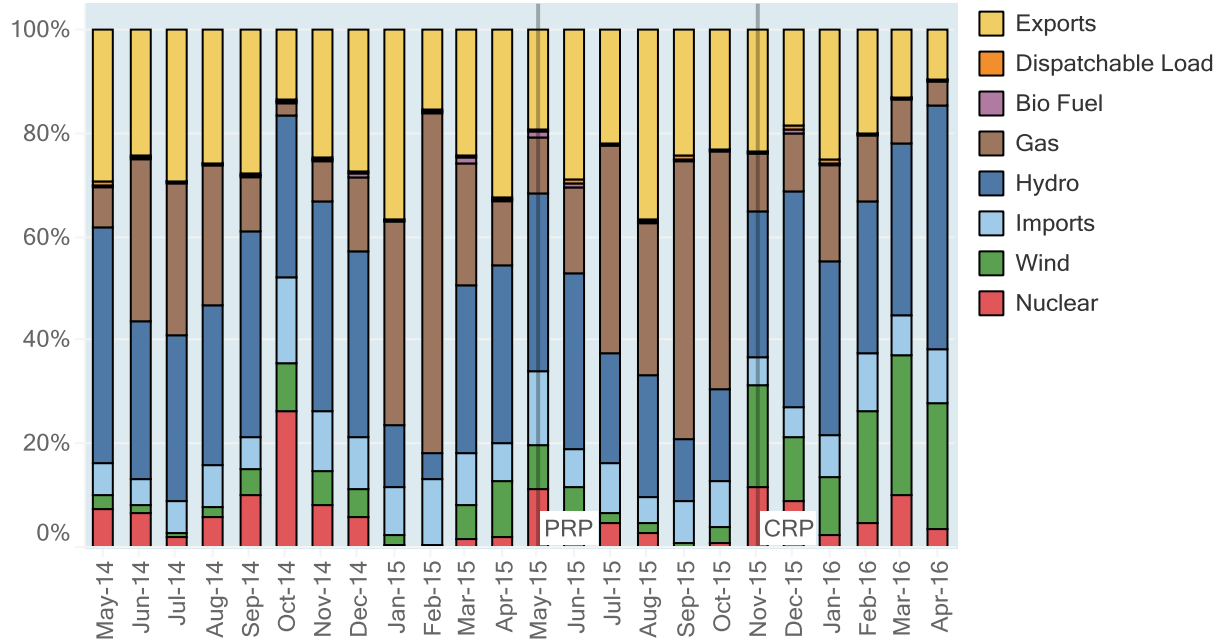
Commentary and Market Considerations:

Wind set the MCP in 30% of all intervals in the Current Reporting Period, which is more frequent than ever before. As installed wind capacity continues to increase in Ontario, the Panel expects wind to continue to set the MCP with increasing frequency, especially during periods of low demand. There has also been a significant reduction in the share of gas generators setting the market clearing price compared to the Previous Reporting Period (from 42.7% to 13.5% of all intervals) as well as compared to the Winter 2015 Period (from 37% to 13.5% of all intervals), because of mild temperatures and higher available capacity from nuclear generation.

Figure 2-7: Share of Resource Type setting the One-Hour Ahead Pre-Dispatch Market Clearing Price
May 2014 – April 2016
(% of hours)

Description:

Figure 2-7 presents the monthly share of hours in which each resource type set the one-hour ahead pre-dispatch (PD-1) MCP, for the previous two years.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

When compared with Figure 2-6 (resources setting the real-time MCP), the relative frequency of each resource type setting the PD-1 MCP provides insight into how the marginal resource mix changes from pre-dispatch to real-time. Of particular importance is the frequency with which imports and exports set the PD-1 MCP, as these transactions are unable to set the real-time MCP.[21] When the price is set by an import or export in pre-dispatch, a divergence between the pre-dispatch and the real-time MCP is more likely to occur.

Commentary and Market Considerations:

Similar to the Commentary for Figure 2-6, two notable observations relate to changes in the share of hours in which wind and gas-fired generators set the PD-1 price. The share of wind setting the PD-1 MCP increased from 3.6% in the Previous Reporting Period to 19.3% in the Current Reporting Period. The share of gas decreased from 33.0% in the Previous Reporting Period and from 27.0% in the 2015 Winter Period to 11.4% in the Current Reporting Period.

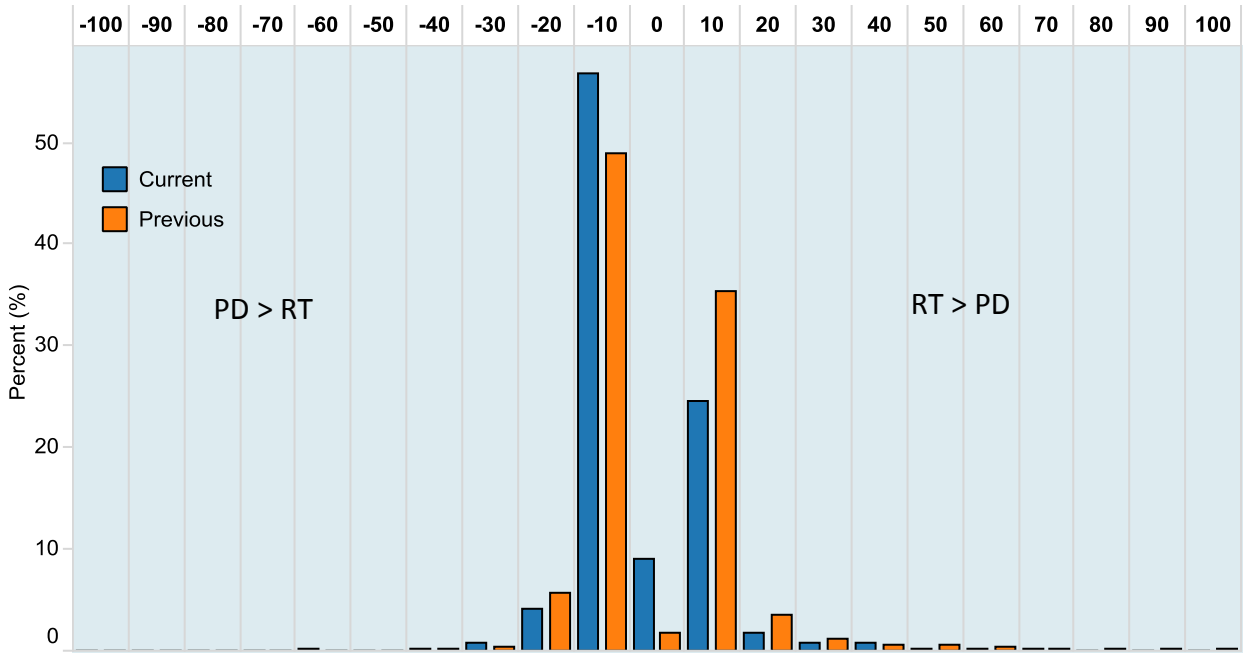
Figure 2-8: Difference between the Hourly Ontario Energy Price and the One-Hour Ahead Pre-Dispatch Price
May 2015 – October 2015 & November 2015 – April 2016
(% of hours)

Description:

Figure 2-8 presents the frequency distribution of differences between the HOEP and the PD-1 MCP for the Current and Previous Reporting Periods. The price differences are grouped in $10/MWh increments, save for the $0/MWh category which represents no change between the PD-1 MCP and the HOEP. The number of instances where the absolute difference between the PD-1 MCP and the HOEP exceeded $100/MWh is negligible and so is not included in Figure 2-8, and the same is true of Figure 2-9 in relation to the absolute difference between the three-hour ahead MCP and the HOEP.

[21] Due to scheduling protocols, imports and exports are scheduled hour-ahead. Therefore, in real-time imports and exports are fixed for any given hour and their prices are adjusted in real-time to -$2,000 and $2,000/MWh, respectively. This means that they are scheduled to flow for the entire hour regardless of the price, though their schedule may change within an hour to maintain reliability. As a result, they are treated like non-dispatchable resources in real-time.

Positive differences on the horizontal axis represent a price increase from pre-dispatch to real-time, while negative differences represent a price decrease from pre-dispatch to real-time.



Relevance:

The PD-1 MCP determines the schedules for import and export transactions for real-time delivery. While intertie transactions are scheduled on the basis of the PD-1 MCP, they are settled on the basis of the HOEP. To the degree that supply and demand conditions change from PD-1 to real-time, imports or exports may be over- or under-scheduled relative to the HOEP. For instance, an exporter that is willing to pay the PD-1 MCP may not want to pay the HOEP if it is higher (due to, for example, a generator outage that occurs between PD-1 and real-time). In such a case, if the exporter was to pay the HOEP they could lose money on the transaction. Conversely, if prices fall, the exporter could see a higher profit but the volume of exports could be sub-optimal.

Commentary and Market Considerations:

Consistent with the Previous Reporting Period, the pre-dispatch sequence over-estimated the HOEP by less than $10/MWh in more than half of all the hours. Almost 10% of the hours had no change in price between the pre-dispatch and real-time frames. The average absolute difference is $5.22/MWh in the Current Reporting Period. As this was $1.36/MWh less than that of the

Previous Reporting Period, this means PD-1 prices in the Current Reporting Period were a more accurate predictor of real-time prices.

Table 2-2: Factors Contributing to Differences between One-Hour Ahead Pre-Dispatch Prices and Real-Time Prices May 2015 – October 2015 & November 2015 – April 2016 (MWh & % of Ontario demand)

Description:

Real-time prices diverge from PD-1 prices as a result of changing conditions from pre-dispatch to real-time. The Panel has identified the following as the six main factors that contribute to the difference between the PD-1 MCP and the HOEP:

Supply

- Self-scheduling and intermittent generation forecast deviation (other than wind);
- Wind generation forecast deviation;
- Generator outages; and
- Import failures/curtailments.

Demand

- Pre-dispatch to real-time demand forecast deviation; and
- Export failures/ curtailments.

Metrics for all but one of these factors are presented in Table 2-2 as the average absolute difference between PD-1 and real-time. The effect of generator outages is not shown in this table as they tend to be infrequent, although short-notice outages can have significant price effects.

Factor	Current		Previous		Winter 2015	
	Average Absolute Difference (MW per hour)	Average Absolute Difference (% of Ontario Demand)	Average Absolute Difference (MW per hour)	Average Absolute Difference (% of Ontario Demand)	Average Absolute Difference (MW per hour)	Average Absolute Difference (% of Ontario Demand)
Ontario Average Demand	15,435		15,205		16,461	
Pre-dispatch to Real-time Demand Forecast Deviation	219	1.42	211	1.39	213	1.29
Self-Scheduling and Intermittent Forecast Deviation (Excluding Wind)	65	0.42	81	0.53	55	0.33
Wind Deviation	114	0.74	112	0.74	126	0.77
Net Export Failures/Curtailments	90	0.59	82	0.54	76	0.61

Relevance:

Identifying the factors that lead to deviations between the PD-1 MCP and the HOEP provides insight into the root causes of price risks that participants, particularly importers and exporters, face as they enter offers and bids into the market.

Commentary & Market Considerations:

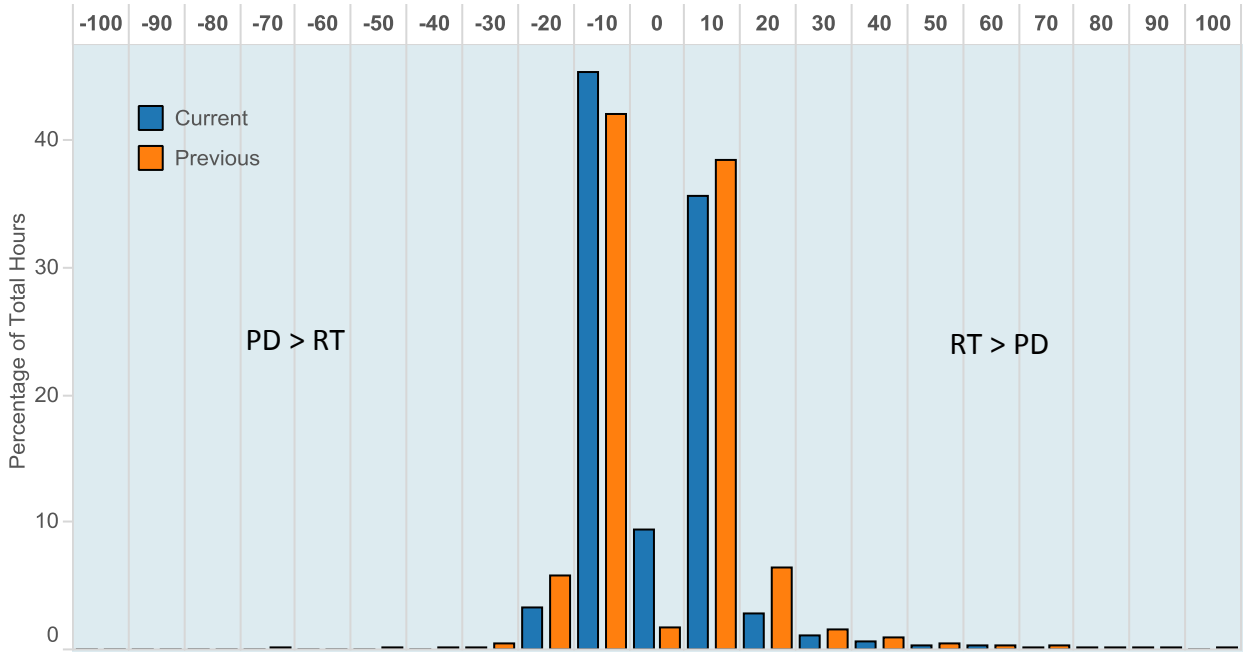
Demand forecast deviation continues to be the largest source of price deviation, while wind forecast deviation remains the second largest factor. Compared to the Previous Reporting Period, the demand forecast deviation and wind forecast deviation remained largely unchanged.

Figure 2-9: Difference between the Hourly Ontario Energy Price and the Three-Hour Ahead Pre-Dispatch Price
May 2015 – October 2015 & November 2015 – April 2016
(% of hours)

Description:

Figure 2-9 presents the frequency distribution of differences between the HOEP and the three-hour ahead pre-dispatch (PD-3) MCP for the Current and Previous Reporting Periods. The price differences are grouped in $10/MWh increments, save for the $0/MWh category which represents no change between the PD-3 MCP and the HOEP. Positive differences on the

horizontal axis represent a price increase from pre-dispatch to real-time, while negative differences represent a price decrease from pre-dispatch to real-time.



Relevance:

The PD-3 MCP is the last price signal seen by the market prior to the closing of the offer and bid window, after which offers and bids may only be changed with the approval of the IESO. Differences between the HOEP and the PD-3 MCP indicate changes in the supply and demand conditions from PD-3 to real-time. The resultant changes in price are informative for non–quick start facilities and energy limited resources,[22] both of which rely on pre-dispatch prices to make operational decisions. Price changes are also important to intertie traders, whose bids and offers are often informed by pre-dispatch prices in Ontario.

Commentary and Market Considerations:

The frequency distribution of differences is similar between the PD-3 MCP and the PD-1 MCP. Compared to the Previous Reporting Period, PD-3 prices were better predictors of real-time prices, with smaller average and absolute average differences along with their associated standard deviations. In addition, 90% of hours observed an absolute difference smaller than

[22] Energy limited resources constitute a subset of generation facilities that experience fuel restrictions such that they cannot operate at capacity for the entire day; instead, they must optimize their production across the highest-priced hours. For example, some hydroelectric facilities regularly experience fuel restrictions due to limited water availability.

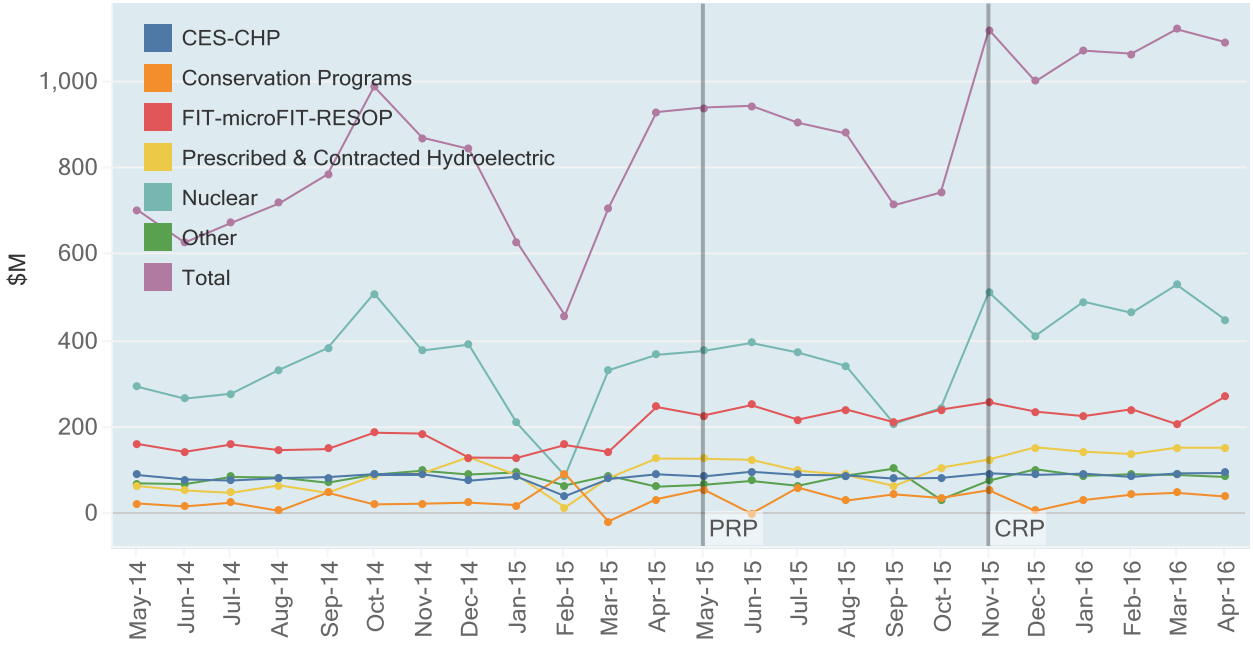
$10/MWh in the Current Reporting Period, compared to approximately 82% in the Previous Reporting Period.

Figure 2-10: Monthly Global Adjustment by Components
May 2014 – April 2016
($)

Description:

Figure 2-10 plots the revenue recovered through the GA each month, by component, for the previous two years. For this purpose, the total GA is divided into the six following components:

- Payments to nuclear facilities (Bruce Nuclear Generating Station and Ontario Power Generation's (OPG's) nuclear assets);
- Payments to holders of Clean Energy Supply and Combined Heat and Power contracts;
- Payments to prescribed or contracted hydroelectric generation;
- Payments to holders of contracts for renewable power (Feed-in Tariff ("FIT"), microFIT and the Renewable Energy Standard Offer Program);
- Payments related to the IESO's conservation programs; and
- Payments to others (including the IESO's demand response programs, non-utility generators, and OPG's Lennox Generating Station).



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

Showing the GA by component identifies the extent to which each component contributes to the total GA. The high GA totals for a particular component may be the result of increases in contracted rates, increased production, increased capacity, or decreases in the HOEP.

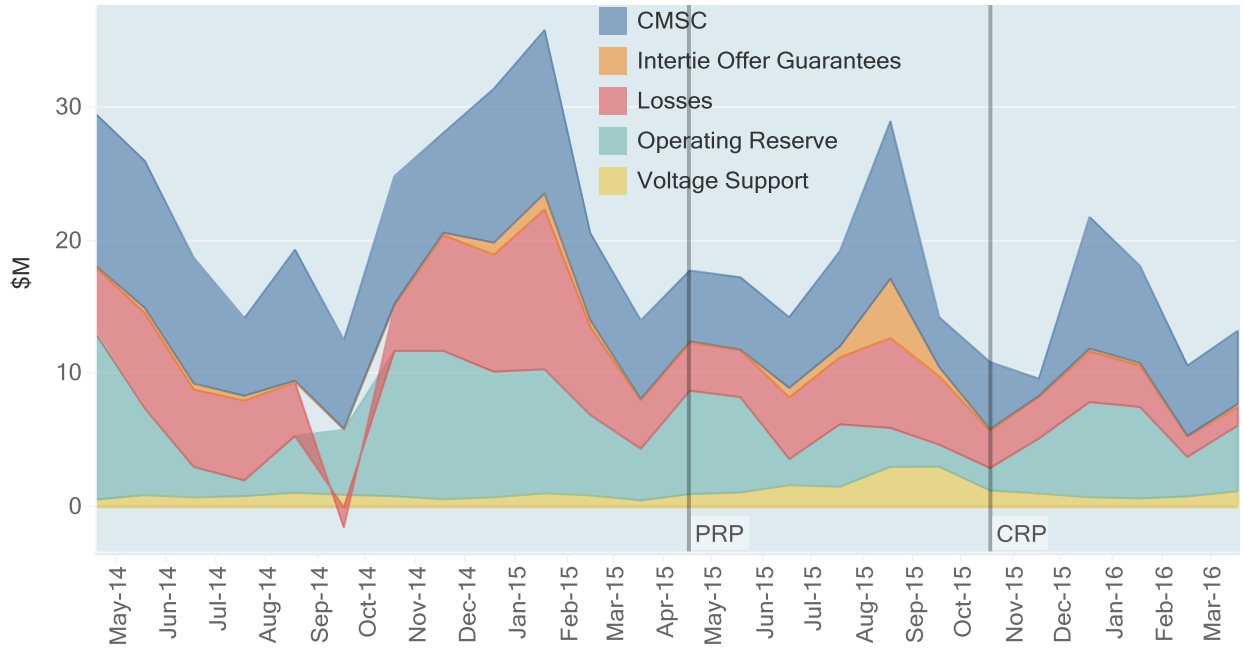
Commentary and Market Considerations:

The overall GA reached a record high of about $6.5 billion in the Current Reporting Period, owing to a comparatively mild winter resulting in lower demand and relatively low HOEP. The increase in GA is also largely attributed to the differential in nuclear payouts, which were much higher in the Current Reporting Period ($2.9 billion) compared to the Previous Reporting Period ($1.9 billion) because of a reduction in nuclear outages. Total FIT and microFIT GA payments also reached new highs ($1.4 billion) during the Current Reporting Period, reflecting an increase of approximately another 400 MW of wind and solar capacity in conjunction with the lower average HOEP.

Figure 2-11: Total Hourly Uplift Charge
By Component and Month
May 2014 – April 2016
($)

Description:

Figure 2-11 presents the total hourly uplift charges (Hourly Uplift) by component and month, for the previous two years. Hourly Uplift components include Congestion Management Settlement Credit (CMSC) payments, day-ahead and real-time Intertie Offer Guarantee (IOG) payments, Operating Reserve (OR) payments, voltage support payments, and losses.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

Hourly Uplift is a component of the effective electricity price in Ontario. It is charged to wholesale consumers (including distributors) based on their share of total hourly demand in order to recover the costs associated with various market programs and design features.

Commentary and Market Considerations:

The Current Reporting Period had a lower peak hourly uplift than the Previous Reporting Period or the Winter 2015 Period, with negligible intertie offer guarantee payments. CMSC and OR were the largest sources of uplift. The relatively high OR payouts from January to February 2016 are largely attributed to increases in OR prices resulting from scarcity conditions, the mechanics of which were described by the Panel in its November 2016 Monitoring Report[23] and are mentioned in the commentary for Figure 2-13 below.

[23] Refer to MSP 27, Chapter 2.

Figure 2-12: Total Monthly Uplift Charge by Component and Month May 2014 – April 2016 ($)[24]

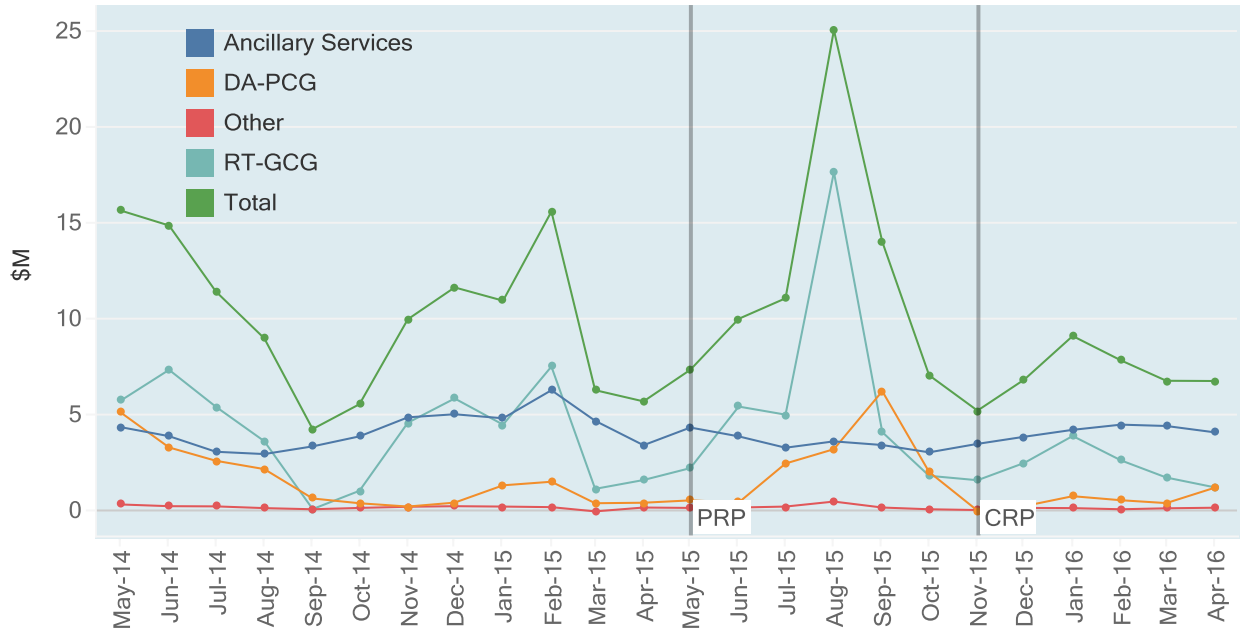
Description:

Figure 2-12 plots the total monthly uplift charges (Monthly Uplift) by component and month, for the previous two years. Monthly Uplift has the following components:[25]

- Payments for ancillary services (i.e., regulation service, black start capability, monthly voltage support);
- Payments for demand response capacity obligations under the DR auction;
- Guarantee payments to generators — Day-Ahead Production Cost Guarantee (DA-PCG) payments made under the IESO's Day-Ahead Commitment Program and Real-Time Generation Cost Guarantee (RT-GCG) payments made under the IESO's RT-GCG program; and
- Other, which includes charges and rebates such as compensation for administrative pricing, the local market power rebate, among others.

[24] The Panel has amended the manner in which it classifies monthly uplift charges to more closely align reported costs with the month in which they were incurred rather than the month in which they were settled. This primarily impacts the monthly reported totals for GCG payments. For example, in Figure 1-12 below, all costs submissions to the GCG program for starts occurring between August 11 and September 9, 2015 were settled at the end of September. However, the bulk of the settlements pertain to starts that occurred in August 2015. As such, the Panel reports these costs below to have occurred in August 2015, rather than September 2015. As a result of this change, monthly totals reported in this report will not match those previously reported by the Panel.

[25] The Monthly Uplifts in this figure are all uplifts that are charged other than on an hourly basis.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

Monthly Uplift is a component of the effective electricity price in Ontario. It is charged to wholesale consumers (including distributors) based on their share of total daily or monthly demand, as applicable, in order to recover the costs associated with various market programs and design features.

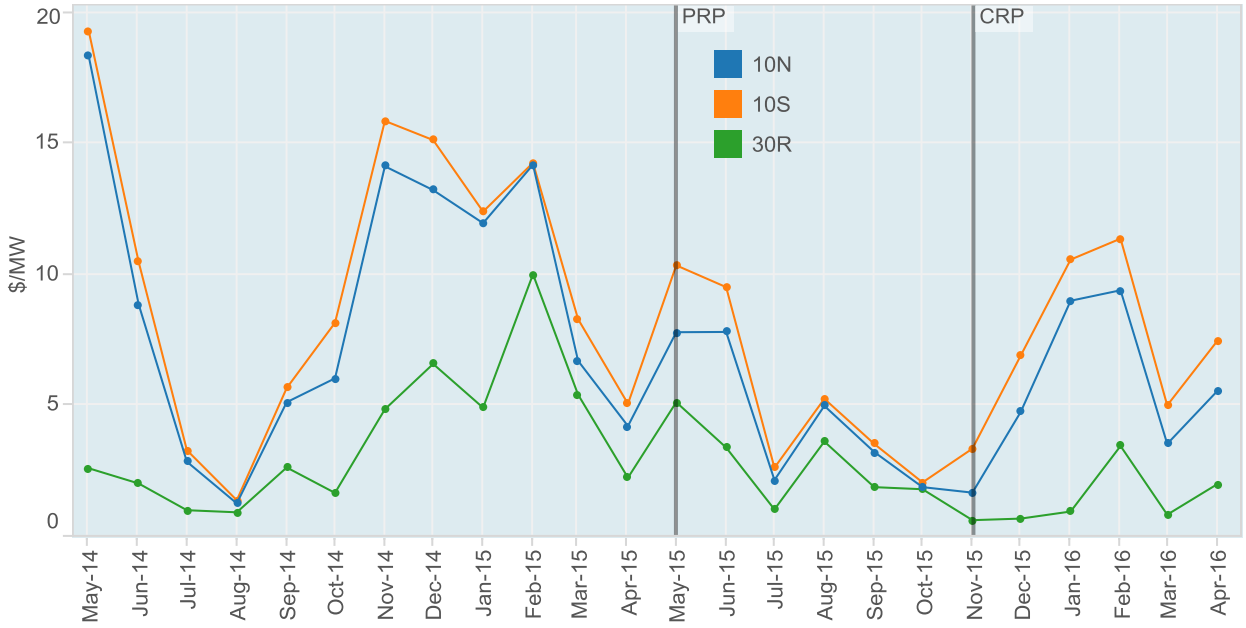
Commentary and Market Considerations:

The Current Reporting Period had relatively low monthly uplifts compared to the Previous Reporting Period. The highest monthly uplift figure during this period was $9.1 million, whereas the highest monthly uplift in the Previous Reporting Period was $25 million. The decline in Monthly Uplift over the Current Reporting Period is partially due to the decline in RT-GCG payments, from a total of $36.3 million in the Previous Reporting Period to a total of $13.7 million in the Current Reporting Period.

Figure 2-13: Average Monthly Operating Reserve Prices, by Category May 2014 – April 2016 ($/MWh)

Description:

Figure 2-13 plots the monthly average OR price for the previous two years for the three OR markets: 10-minute spinning (10S), 10-minute non-spinning (10N), and 30 minute (30R).



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

The three OR markets are co-optimized with the energy market, meaning that resources are scheduled to minimize the combined costs of energy and OR. As such, prices in these markets tend to be subject to similar dynamics.

Resources offer supply into the OR markets just as they offer supply into the energy market; however, OR demand is set unilaterally by the IESO's total OR requirement. The total OR requirement, as specified in the reliability standards adopted by the North American Electric Reliability Corporation and the Northeast Power Coordinating Council, is sufficient megawatts to allow the grid to recover from the single largest contingency (such as the largest generator tripping offline) within 10 minutes, plus additional OR to recover from half of the second largest

contingency within 30 minutes. These requirements ensure that the IESO-controlled grid can operate reliably.

Commentary and Market Considerations:

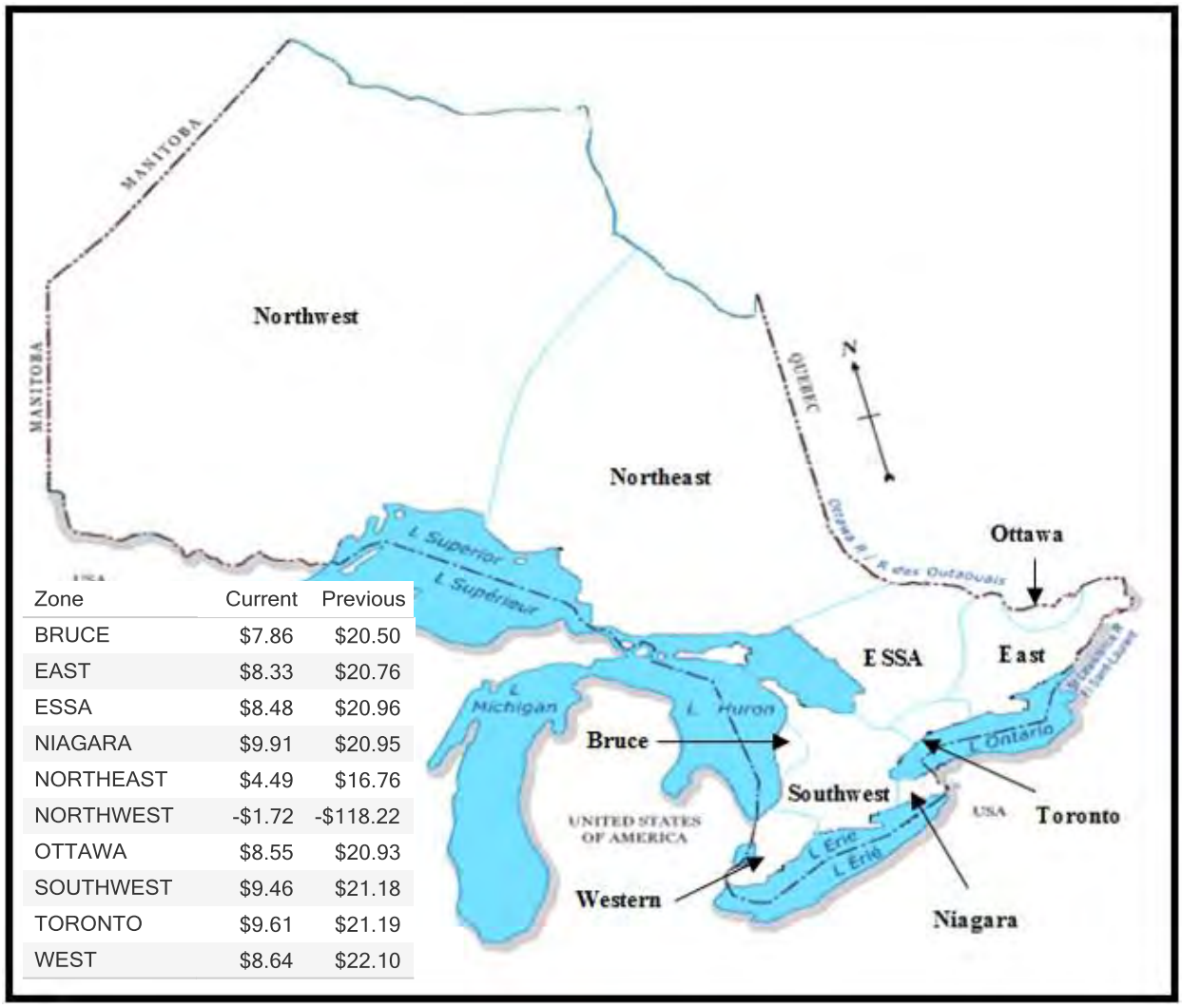
OR prices are higher relative to the Previous Reporting Period but are lower compared to the Winter 2015 period. January and February 2016 experienced relatively higher OR prices due to OR scarcity. While the majority of OR is offered by gas-fired and hydro-electric facilities, two factors have contributed to their decline. First, OR offers from hydroelectric resources have been decreasing for several years; this may be because OR revenue received by Ontario Power Generation's hydro-electric facilities is subtracted from the facilities' revenue requirement.[26] Therefore, OPG may not have a significant incentive to maximize OR revenues. The other contributor relates to Ontario's supply mix: abundant low marginal-cost supply in the form of nuclear, wind, and solar more frequently represent the marginal resource in Ontario; however, none of these resources can provide OR. When those low marginal cost resources are marginal, most non-quick start gas-fired facilities are not online, and therefore are not available to provide 10-minute operating reserve. This can result in short supply in the OR market, which generally results in higher OR prices and the increased potential of OR shortfalls. The Panel expects that higher OR prices will become more prevalent as even more renewable capacity is contracted and brought online.

Figure 2-14: Average Internal Nodal Prices by Zone
May 2015– October 2015 & November 2015 – April 2016
($/MWh)

Description:

Figure 2-14 illustrates the average nodal price of Ontario's ten internal zones for the Current and Previous Reporting Periods. In principle, nodal prices represent the cost of supplying the next megawatt of power at a given location.

[26] Refer to section 2.6 of MSP 27 Chapter 2 to examine in greater details the reasons for declining OR offers.



Zone	Current	Previous
BRUCE	$7.86	$20.50
EAST	$8.33	$20.76
ESSA	$8.48	$20.96
NIAGARA	$9.91	$20.95
NORTHEAST	$4.49	$16.76
NORTHWEST	-$1.72	-$118.22
OTTAWA	$8.55	$20.93
SOUTHWEST	$9.46	$21.18
TORONTO	$9.61	$21.19
WEST	$8.64	$22.10

Relevance:

While the HOEP is the uniform wholesale market price across Ontario, the cost of satisfying demand for electricity may differ across the province due to limits on the transmission system and the cost of generation in different regions. Nodal prices approximate the marginal value of electricity in each region and reflect Ontario's internal transmission constraints. Differences in average nodal prices identify zones that are separated by system constraints. In zones in which average nodal prices are high, the supply conditions are relatively tight; in zones in which average nodal prices are low, the supply conditions are relatively more abundant.

In general, nodal prices outside the northern parts of the province move together. Most of the time the nodal prices in the Northwest and Northeast zones are significantly lower than the nodal prices in the rest of the province due primarily to two factors: first, in these zones, there is

surplus low-cost generation (in excess of local demand); and second, there is insufficient transmission to transfer this low-cost surplus power to the southern parts of the province.

Contributing to negative prices in the northern zones are hydroelectric facilities operating under must-run conditions. Must-run conditions necessitate that units generate at certain levels of output for safety, environmental, or regulatory reasons. Under such conditions, market participants offer the must-run energy at negative prices in order to ensure that the units are economically selected and scheduled.

Commentary and Market Considerations:

Nodal prices decreased among all zones, with the exception of the Northwest zone, where prices increased but were still negative. In line with changes in the HOEP attributed to milder winter conditions, relatively low demand during the Current Reporting Period resulted in lower nodal prices. In general, most zonal prices tend to move together, expect when there are outages on major transmission lines. With respect to the Northwest, however, increased net exports to Manitoba and Minnesota, as noted in Figure 2-26, were likely contributors to the price increase.

Figures 2-15 & 2-16: Congestion by Interface Group

Description:

Figures 2-15 and 2-16 report the number of hours per month of import and export congestion, respectively, by interface for the previous two years.

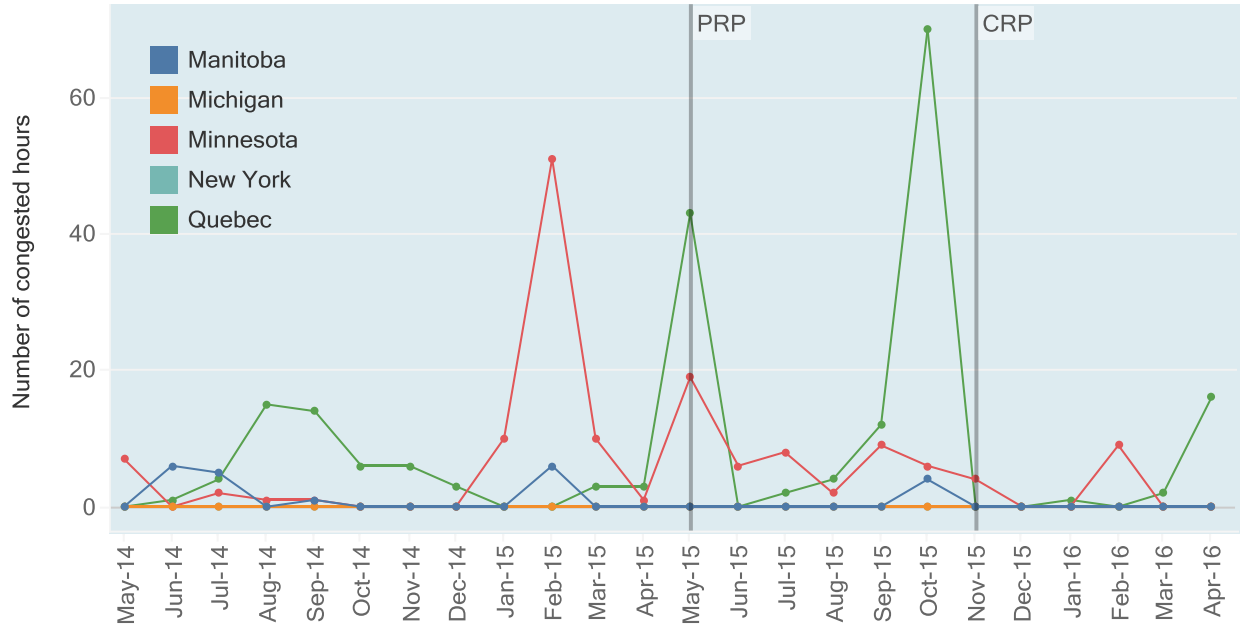
Relevance:

The interties that connect Ontario to neighbouring jurisdictions have finite transfer capabilities. The supply of intertie transfer capability is dictated by the available capacity at each interface, and also by line outages and de-ratings. When an intertie has a greater amount of economic net import offers (or economic net export bids) than its one-hour ahead pre-dispatch transfer capability, the intertie will be import (or export) congested. Demand for intertie transfer capability is driven in part by price differences between Ontario and other jurisdictions.

The price for import and export transactions can differ from the MCP, as it is based on the intertie zonal price where the transaction is taking place. For a given intertie, importers are paid the intertie zonal price, while exporters pay the intertie zonal price. When there is import

congestion, importers receive less for the energy they supply while exporters (if any) pay less for the energy they purchase—the intertie zonal price is lower than the MCP. When there is export congestion, importers (if any) receive more for the energy they supply while exporters pay more for the energy they purchase—the intertie zonal price is greater than the MCP. The difference between the intertie zonal price and the MCP is called the Intertie Congestion Price (ICP). The ICP for a given hour is calculated in PD-1 depending on whether or not the PD-1 energy schedule has more energy transactions than the intertie transmission lines can withstand. The ICP is positive when there is export congestion and negative when there is import congestion. This is discussed in more detail in the "Relevance" section associated with Figure 2-17.

Figure 2-15: Import Congestion by Interface Group
May 2014 – April 2016
(number of hours in the unconstrained schedule)

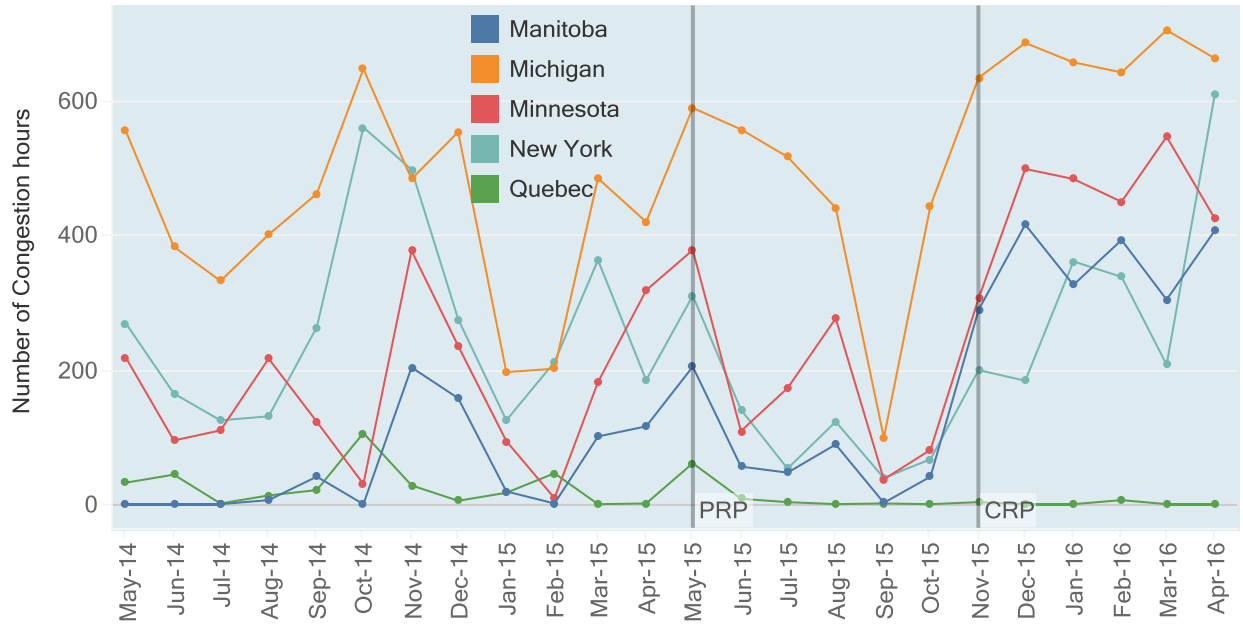


*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Commentary and Market Consideration:

Overall there were fewer import congestion hours compared to the Previous Reporting Period. Low HOEP in the Current Reporting Period resulted in relatively few imports. A depreciation of the Canadian dollar compared to the US dollar also has the effect of decreasing the profitability of importing power.

Figure 2-16: Export Congestion by Interface Group
May 2014 – April 2016
(number of hours in the unconstrained schedule)



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Commentary and Market Consideration:

Export congestion increased for every intertie with the exception of Quebec. Low HOEP relative to the price in other jurisdictions had led to greater export opportunities relative to intertie capacity, leading to increased intertie congestion. Depreciation of the Canadian dollar compared to the US dollar also has the effect of increasing the profitability of exporting power.

The significant increase in export congestion hours on the New York intertie from March 2016 to April 2016 is due to transmission line limitations having restricted the New York intertie limit by at least 600 MW for approximately 66% of all hours in April.

Table 2-3: Monthly Average Hourly Wholesale Electricity Prices
in Ontario and Surrounding Jurisdictions
November 2015 – April 2016
($/MWh)

Description:

Table 2-3 lists the average hourly real-time wholesale prices for electricity, by month, in Ontario and the surrounding external jurisdictions with which electricity intertie traders operating in

Ontario commonly trade. The Ontario price reported is the HOEP. Absent congestion at an interface, importers receive, and exporters pay, the HOEP when transacting in Ontario.

The external prices reported are the real-time location-marginal prices ("LMPs") that correspond with the node on the other side of Ontario's interface with each jurisdiction. A proxy price was calculated for Manitoba as it does not operate a market. Quebéc is a frequent trading partner, but also does not operate a market. No proxy price was calculated for Quebéc. All prices are listed in Canadian dollars.

Month	Ontario (HOEP)[27]	Manitoba[28]	Michigan (MISO)[29]	Minnesota (MISO)[30]	New York (NYISO)[31]	Pennsylvania New Jersey Maryland Operator (PJM)[32]
Nov	9.29	19.26	22.72	31.27	16.91	30.50
Dec	10.04	24.15	25.65	29.90	17.90	29.67
Jan	12.78	29.22	30.55	31.56	23.69	35.90
Feb	11.5	24.41	26.43	29.46	19.19	31.79
Mar	5.19	19.24	21.99	26.65	10.45	18.06
Apr	5.73	17.98	21.00	28.18	24.77	27.71

Relevance:

One objective of energy trading is to exploit arbitrage opportunities. Intertie traders attempt to purchase (export) low-priced power from one jurisdiction and sell (import) that power to another jurisdiction at a higher price to capture the price differential.[33]

[27] All prices listed for each jurisdiction reflect the marginal price of energy. Costs associated with capacity, such as Ontario`s global adjustment or NYISO, PJM, or MISO's capacity markets, are not considered in inter-jurisdictional trade.
[28] The Panel assumed that the real-time LMPs at the 'MHEB' node published by MISO are representative of the external prices at the Manitoba interface.
[29] The Panel assumed that the real-time LMPs at the 'ONT_DECO_PSOUT' node published by MISO are representative of the external prices at the Michigan interface.
[30] The Panel assumed that the real-time LMPs at the 'ONT_W' node published by MISO are representative of the external prices at the Minnesota interface.
[31] The Panel assumed that the real-time LMPs at the 'OH' node published by NYISO are representative of the external prices at the New York interface.
[32] The Panel assumed that the real-time LMPs at the 'IMO' node published by PJM are representative of the external prices in PJM that exporters can capture by wheeling through New York or Michigan.
[33] Differences exist in terms of the specific costs that are included in the spot price of electricity between jurisdictions. For example, in Ontario, the HOEP is not reflective of a gas-fired generation unit's start-up costs, as these costs are a component of uplift, which is settled out-of-market. The specific components that comprise the spot price will vary from jurisdiction to jurisdiction, but they are still the most accurate and readily available indicators of economic decision making in real-time for intertie traders.

Price differences between jurisdictions can change from one hour to the next due to changes in any of the numerous factors which determine demand (e.g. weather) and supply (e.g. outages). Changes in the price differential will impact the direction of energy trade between those jurisdictions. Energy trade may not always flow from jurisdictions with low prices to jurisdictions with high prices; imperfect information, timing issues and rapidly changing conditions can lead to energy trade that appeared efficient ex-ante but ends up being inefficient or unprofitable ex-post. However, average prices over longer time horizons should be informative on trends in the direction of energy trade between jurisdictions. Over the course of a month if the average energy price in Ontario is lower than another jurisdiction, energy trade should flow from Ontario to that jurisdiction in that month on a net basis.

Congestion can erode or even reverse the original arbitrage opportunity between the HOEP and the external jurisdiction's price. However, the two key pieces of information in determining whether to import to or export from Ontario are the HOEP and the spot price in the external jurisdiction.

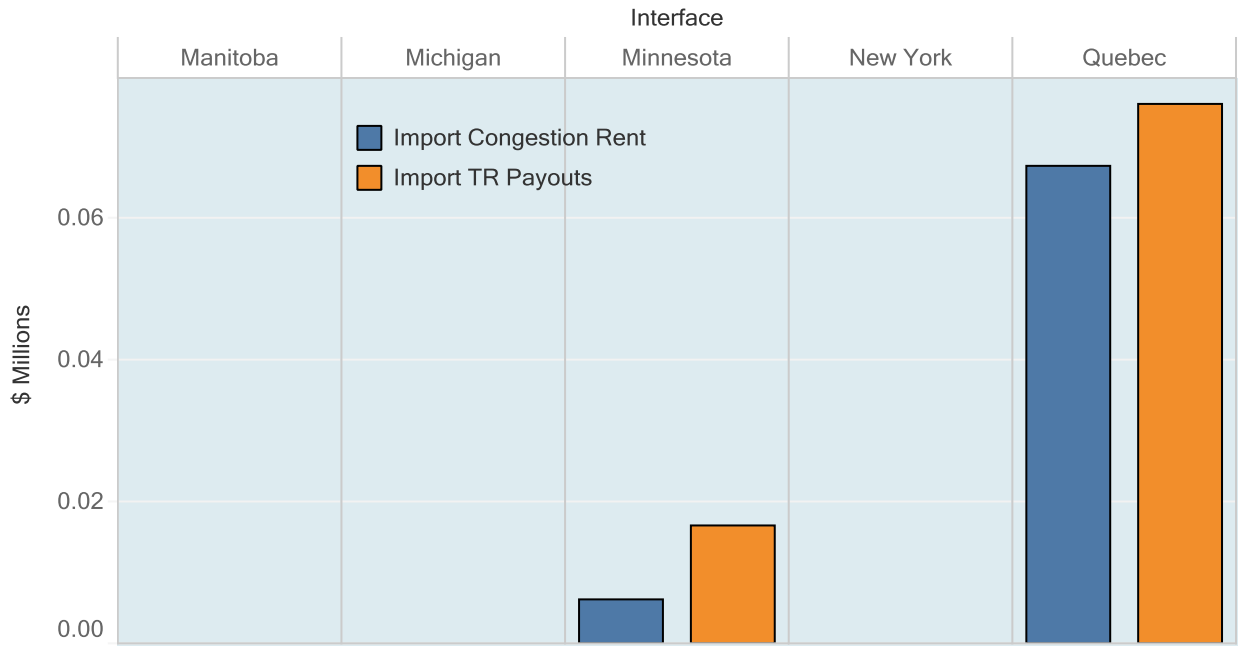
Commentary and Market Considerations:

In line with observations from Figures 2-15 and 2-16, Ontario's HOEP was significantly lower than the energy price in all of the surrounding jurisdictions; hence it was a net exporter during the Current Reporting Period.

Figure 2-17: Import Congestion Rent &
Transmission Rights Payouts by Interface Group
November 2015 – April 2016
($)

Description:

Figure 2-17 compares the total collection of import congestion rent to total TR payments by interface group for the Current Reporting Period.



Relevance:

As discussed in the relevance section associated with Figures 2-15 and 2-16, an intertie zonal price is less than the Ontario price when an intertie is import congested; the difference in prices is the ICP and is equal to the difference (if any) between the PD-1 Ontario price and the PD-1 intertie zonal price. While the importer is paid the lesser intertie zonal price, the buyer in the wholesale market still pays the HOEP. The difference between the amount collected from the purchaser and the amount paid to the importer is known as import "congestion rent". Congestion rent accrues to the IESO's TR Clearing Account. This account is discussed in greater detail in the Relevance section associated with Figure 2-19.

To enable intertie traders to hedge against the risk of price fluctuations due to congestion, the IESO administers TR auctions. TRs are sold on the basis of intertie and direction (import or export) for periods of one month or one year. The owner of a TR is entitled to a payment (or "payout") equal to the ICP multiplied by the amount of TRs they hold every time congestion occurs on the intertie in the direction for which they own a TR. TRs therefore allow an intertie trader to hedge against congestion-related price fluctuations by ensuring that intertie traders are settled on the HOEP and not the intertie zonal price. An intertie trader that holds the exact same amount of import TRs as the amount of energy they are importing is perfectly hedged against

congestion, as TR payouts will exactly offset price differences between the Ontario price and the price in the intertie zone. Payouts to TR holders are disbursed from the TR Clearing Account.

While TR payouts should theoretically be offset by congestion rent collected, in practice this is seldom the case. One of the main reasons for this is the difference between the number of TRs held by market participants and the number of net imports/exports flowing during hours of congestion. When TR payouts exceed congestion rent collected, the TR Clearing Account is drawn down; the opposite is true when congestion rent collected exceeds TR payouts.

In addition to congestion rent collected and TR payouts, there is a third input to the TR Clearing Account—TR auction revenues. TR auction revenues are the proceeds from selling TRs (a payment into the TR Clearing Account). Due to Ontario's two-schedule price system,[34] transaction failures and intertie de-ratings, there are congestion events in which a congestion rent shortfall arises; instead of remaining revenue neutral, these events draw down the TR Clearing Account. These shortfalls are covered primarily by TR auction revenues. The Panel has previously expressed the view that TR auction revenues should be for the benefit of consumers in the form of a reduction in transmission charges.[35] In that context, every dollar of congestion rent shortfall represents a dollar that does not accrue to the benefit of Ontario customers. The IESO has recently made changes to its TR auction process to address recurring congestion rent shortfalls, which is discussed further in the Relevance section associated with Figure 2-19.

Note that interties with a high frequency of import congestion hours (see Figure 2-15) do not necessarily correlate with high import TR payouts and import congestion rent, primarily because of the differences in intertie capacity (and thus TRs sold) at each intertie.

[34] Intertie congestion (and thus the ICP and TR payouts) is calculated based on the pre-dispatch unconstrained schedule, while congestion rent collected is based on the real-time constrained schedule. To the degree that the pre-dispatch unconstrained schedule differs from the real-time constrained schedule, TR payouts may differ from congestion rent collected. In the extreme, congestion may occur in one direction (*e.g.,* import) in the pre-dispatch unconstrained schedule, but the real-time constrained schedule has net transactions in the opposite direction (*e.g.,* export). In this case, import TR payouts are made and negative import congestion rents are "collected".

[35] If there were no TRs in Ontario, but all other aspects of the market design were retained, congestion rent would still be collected by the IESO whenever there was congestion on an intertie. Those congestion rents are the price importers and exporters are prepared to pay for scarce transmission capacity, suggesting that rents might be paid to transmission owners. But as the transmission companies are rate-regulated entities, any congestion rents paid to them would presumably be used to offset their regulated revenue requirement. Thus, their customers (Ontario consumers) would benefit from congestion rents. For more information on the TR market and the basis for disbursing funds from the TR Clearing Account to offset transmission service charges, see the Panel's January 2013 Monitoring Report, pages 146-160, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2011-Apr2012_20130114.pdf

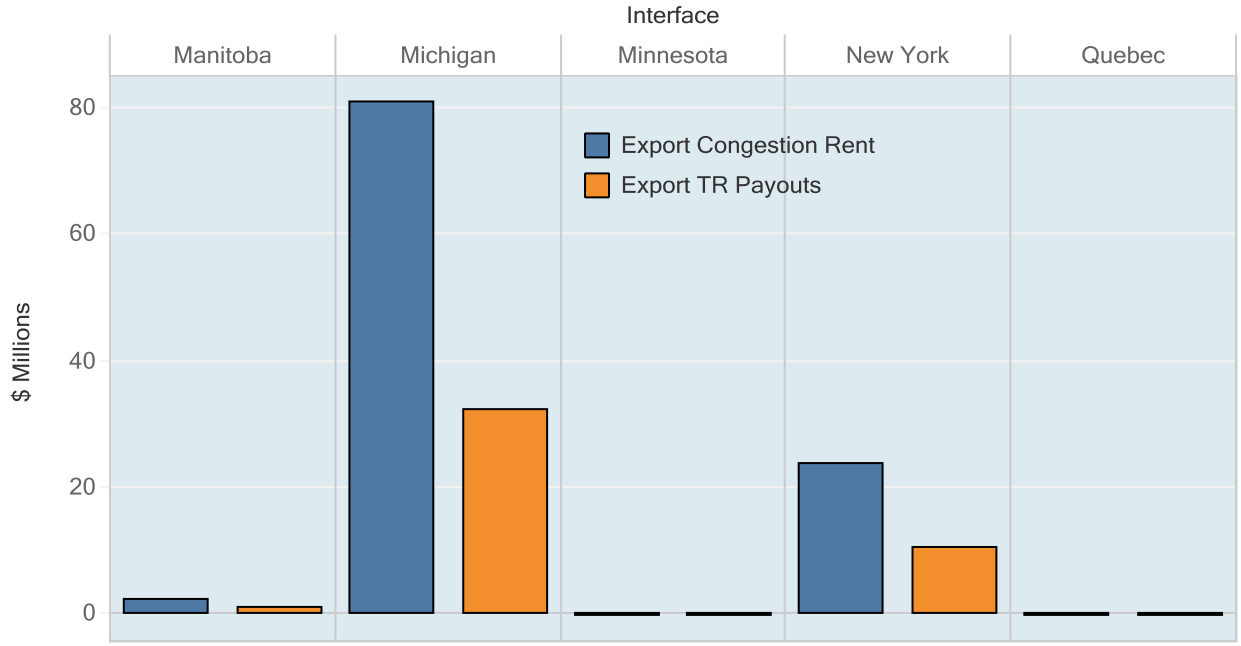
Commentary and Market Consideration:

There were very little import congestion rents paid out during the Current Reporting Period. This is because the HOEP was considerably less than the market prices in neighbouring jurisdictions, meaning there were fewer opportunities to import.

Figure 2-18: Export Congestion Rent & TR Payouts by Interface Group November 2015 – April 2016 ($)

Description:

Figure 2-18 compares the total collection of export congestion rent to total TR payouts by interface group for the Current Reporting Period.



Relevance:

When there is export congestion, an intertie zonal price is more than the Ontario price. See the Relevance section associated with Figure 2-17 that describes the relationship between congestion rents and TR payments in regards to import congestion. The relationship between congestion rents and TR payments for export congestion is the converse of that for import congestion. In general, if there are less congestion rents collected, there is a congestion rent shortfall (and the TR Clearing Account balance decreases); if there are more congestion rents collected than TR payments, there is a congestion rent surplus (and the TR Clearing Account balance increases).

Commentary and Market Consideration:

Compared to the Previous Reporting Period, export congestion rents for the New York and Michigan interties more than doubled, while TR payouts effectively remained unchanged between the Current and Previous Reporting Periods. The New York and Michigan interfaces were the primary contributors to congestion rent, with the latter being the most heavily export congested interface in the Current Reporting Period, as seen in Figure 2-16. The average hourly export capacity of the interface exceeded average hourly export TR ownership over the Current Reporting period by 346 MW and 99 MW for Michigan and New York respectively. In general, TRs can be undersold relative to the intertie capacity owing to line and equipment outages or system security requirements that suppress the IESO's forecast of the intertie's capacity.

Table 2-4: Average Long-Term (12-month) Transmission Right Auction Prices by Interface and Direction May 2015 – February 2016 ($/MW)

Description:

Table 2-4 lists the weighted average auction prices of 1 MW of long-term (year-long) TRs sold for each interface, in either direction, since May 2015 (these TRs would have been valid during the Current Reporting Period).

Direction	Auction Date	Period TRs are Valid	Manitoba	Michigan	Minnesota	New York	Quebec
Import	May-15	Jul-15 to May-16	3,294	511	5,306	456	2,454
	Aug-15	Oct-15 to Aug-16	2,844	505	4,445	404	1,106
	Nov-15	Jan-16 to Dec-16	1,735	389	3,707	224	1,850
	Feb-16	Apr-16 to Mar-17	1,796	339	3,487	208	1,118
Export	May-15	Jul-15 to May-16	15,883	62,961	26,374	42,910	6,745
	Aug-15	Oct-15 to Aug-16	12,605	72,534	21,850	51,193	9,865
	Nov-15	Jan-16 to Dec-16	8,828	61,875	19,034	29,036	4,383
	Feb-16	Apr-16 to Mar-17	19,595	78,135	25,276	34,165	2,980

Relevance:

If an auction is efficient, the price paid for one megawatt of TRs should reflect the expected payout from owning that TR for the period. This is equivalent to the expected sum of all ICPs in the direction of the TR over the period for which the TR is valid. The greater the expected frequency and/or magnitude of congestion on the intertie, the more valuable the TR. Assuming

an efficient auction, auction revenues signal the market's expectation of intertie congestion conditions for the forward period.

Commentary and Market Consideration:

Given Ontario's position as a net exporter of energy, auctions prices for long-term TRs were generally higher for exports than for imports across all interties. There has been a decrease in long-term import TR prices from the Previous Reporting Period to the Current Reporting Period across all interties: this may be indicative of market participants' expectations that import congestion will not be as prominent in the upcoming winter. With the exception of the New York and Michigan interties, there were no major price fluctuations for long term TR's between the Current and Previous Reporting Periods. The relatively material decrease in long-term export TR prices at New York is predictive of fewer export congestion hours in subsequent monitoring periods. Michigan is the only intertie with long-term TR prices that have increased, albeit slightly, from the Previous to the Current Reporting Period: the high occurrence of export congestion on the Michigan intertie is expected to persist.

Table 2-5: Average Short-Term (One-month) Transmission Right Auction Prices by Interface and Direction
May 2015 – April 2016
($/MW)

Description:

Table 2-5 lists the auction prices for 1 MW of short-term (month-long) TRs sold at each interface, in either direction, during the Previous and Current Reporting Periods.

Direction	Period TRs are Valid	Manitoba	Michigan	Minnesota	New York	Quebec
Import	May-15	310	55	418	90	135
	Jun-15	317	16	-	16	90
	Jul-15	387	12	-	11	81
	Aug-15	417	30	201	7	79
	Sep-15	202	12	164	7	0
	Oct-15	135	19	290	15	118
	Nov-15	165	15	122	15	5
	Dec-15	117	0	201	0	28
	Jan-16	103	0	327	1	20
	Feb-16	121	0	143	0	28
	Mar-16	98	0	126	0	40
	Apr-16	113	14	130	0	82
Export	May-15	810	4,494	1,735	2,262	179
	Jun-15	1,300	5,575	-	2,520	27
	Jul-15	751	6,897	-	2,645	82
	Aug-15	459	7,462	-	930	37
	Sep-15	580	5,947	-	1,125	6
	Oct-15	393	2,701	-	671	123
	Nov-15	310	4,009	-	2,297	72
	Dec-15	457	4,494	-	1,208	220
	Jan-16	1,001	4,621	-	1,305	826
	Feb-16	1,510	6,145	-	1,655	355
	Mar-16	2,612	7,373	-	2,875	186
	Apr-16	2,320	6,586	-	1,523	10

Relevance:

As discussed in the relevance section associated with Table 2-4, auction revenues signal market participant expectations of intertie congestion conditions for the forward period.

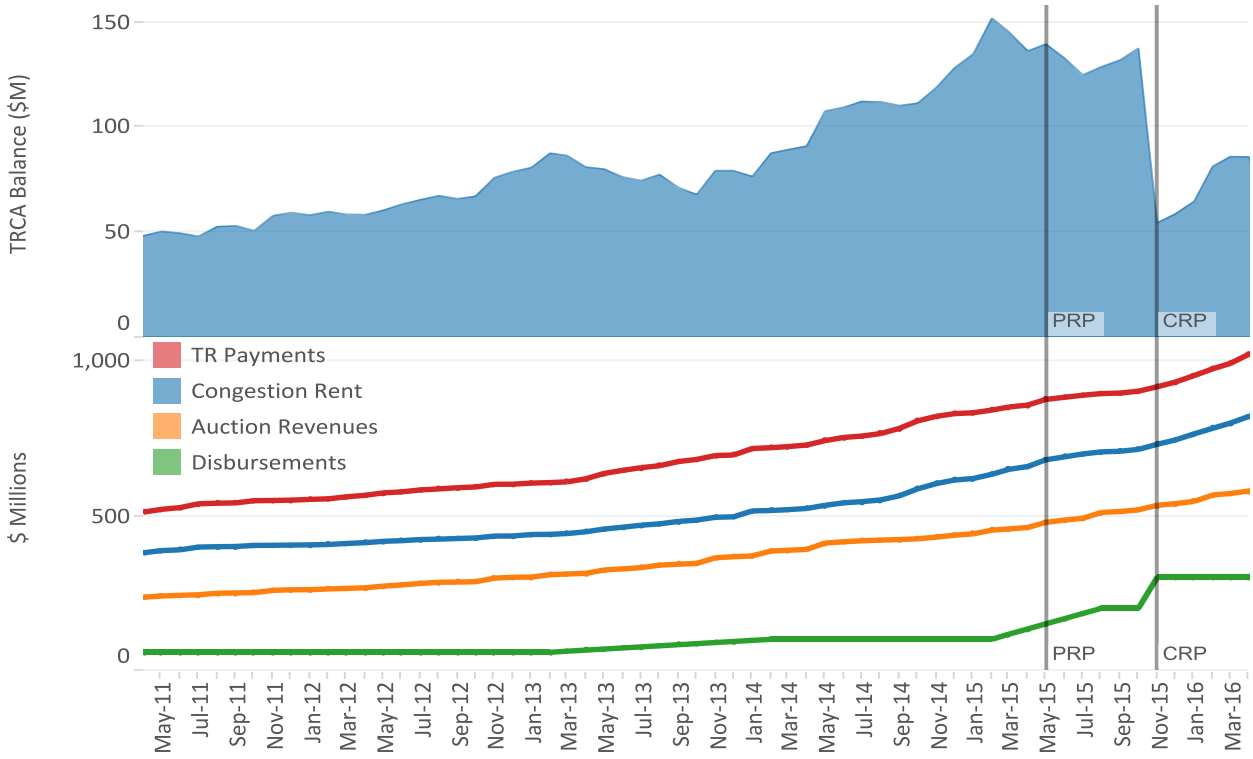
Commentary and Market Consideration:

Short-term import TR prices were consistent with the long-term TR auction. Regarding short-term export TR's, none were sold to Minnesota in this monitoring period. The short-term export TR prices at the Manitoba intertie almost tripled from the Previous to Current Reporting Period, which indicates a correct anticipation for the increased occurrence of export congestion hours at the Manitoba intertie, as illustrated in Figure 2-16. Trends in short-term export TR prices were consistent with the long-term TR auction for New York and Michigan.

Figure 2-19: Transmission Rights Clearing Account
May 2011 – April 2016
($)

Description:

The TR Clearing Account is an account administered by the IESO to record various amounts relating to TRs. Figure 2-19 shows the estimated balance in this account at the end of each month for the previous five years, as well as a breakdown by its component transactions.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

The TR Clearing Account balance is affected by five types of transactions:

Credits

- Congestion rent received from the market
- TR auction revenues
- Interest earned on the TR Clearing Account balance

Debits

- TR payouts to TR holders
- Disbursements to Ontario market participants

Tracking TR Clearing Account transactions over a period of time provides an indication of the health of the TR market and the policies that govern it. The account has a reserve threshold of $20 million set by the IESO Board of Directors; funds in excess of this threshold can be disbursed to wholesale loads and exporters at the discretion of the IESO Board of Directors.

Commentary & Market Considerations:

In the Current Reporting Period, the balance in the TR Clearing Account decreased by $51.78 million; from $137.31 million at the end of the Previous Reporting Period to $85.53 million at the end of the Current Reporting Period, thus ending $65.53 million above the Reserve Threshold. This change was composed of:

- $168.26 million in revenues
    - $107 million in congestion rent collected
    - $60.96 million in auction revenues
    - $0.30 million in interest (this was negligible and was therefore removed from the figure)
- $220.5 million in disbursements
    - $120.05 million in TR payments to rights holders
    - $100 million in disbursement to Ontario consumers in November 2015
        - This particular disbursement is discussed in more detail in Chapter 3 of this report

Total auction revenues increased by $4 million from the Previous Reporting Period to the Current Reporting Period. This change is likely attributed to a net increase in export TR prices coupled with relatively immaterial fluctuations in import TR prices, as summarized in Table 2-4 and Table 2-5.

Congestions rents increased by $52 million, while TR payouts increased by $75 million from the Previous Reporting Period to the Current Reporting Period. As noted in Figure 2-16, depreciation in the Canadian dollar relative to the US dollar had the effect of increasing the profitability of exporting power. This has contributed to an increase in the number of export congestion hours in all interties from the Previous Reporting Period to the Current Reporting Period, which in turn has increased the opportunity to collect congestion rents and make TR payments.

The Panel expands on the interdependencies between each component of the TR Clearing Account from section 3.1.1 to section 3.1.2 of Chapter 4.

Table 2-6: Demand Response Auction Results in December 2015 (MW, $/MW-day)

Description

Table 1-6 summarizes the results of the IESO's inaugural Demand Response (DR) Auction, completed in December 2015 for the subsequent summer (May 1, 2016 to October 31, 2016) and winter (November 1, 2016 – April 30, 2017) commitment periods. In general, DR consists of programs that encourage customers to reduce demand during times of tight supply conditions. DR is meant to reduce the total peak demand, or be used at other times to assist with maintaining reliability, as an alternative to calling on generators to produce more energy. As specified by the capacity obligation within each zone, resources committed through the DR auction are available to provide relief by reducing their consumption when called upon. Successful resources from the DR auction receive the auction clearing price for each MW of DR capacity.[36]

Zone	Summer Commitment Period (May 1, 2016 - Oct 31, 2016)		Winter Commitment Period (Nov 1, 2016 - Apr 30, 2017)	
	Capacity Obligation (MW)	Auction Clearing Price ($/MW-day)	Capacity Obligation (MW)	Auction Clearing Price ($/MW-day)
BRUCE	-	-	-	-
EAST	24.7	378.21	25.4	359.87
ESSA	13.7	378.21	13.8	359.87
NIAGARA	15.9	348.45	15.9	332.71
NORTHEAST	56.3	378.21	56.3	359.87
NORTHWEST	51	378.21	50	359.87
OTTAWA	10.8	378.21	11.2	359.87
SOUTHWEST	40	378.21	55.3	359.87
TORONTO	159.4	378.21	159.2	359.87
WEST	19.7	378.21	16.6	359.87
Total MW	**391.5**	-	**403.7**	-
Weighted Average Price	-	**377.00**	-	**358.80**

[36] See Chapter 3 for an in-depth explanation of the DR auction process.

Relevance

The DR Auction is part of the IESO's transitional program to migrate the procurement of demand response from previous multi-year, contracted programs into a more competitive, near-term market mechanism within the IESO-administered markets. Instituting the DR Auction is viewed by the IESO as a foundational step to introduce a market-based mechanism to procure capacity, with the aim to allow for the entry of new, cost-effective demand response providers, enable system flexibility, and evolve the demand response sector to eventually compete with conventional forms of capacity such as supply or import resources. The DR Auction is also one of the key instruments the IESO is using to work towards the policy goal set forth in the 2013 Long Term Energy Plan of reducing peak demand by 10% in 2025.

Commentary

As Ontario has 10 electrical zones with varying supply and demand conditions, the auction took place on a zonal level by creating limits for the amount of DR procured in each zone. Zones with more generation than load would require less DR, while zones with more load than generation can have DR playing a greater role in matching supply and demand. For these reasons, Toronto was the zone with the greatest capacity obligation, holding 40.7% and 39.4% of the total capacity obligation in the summer and winter commitment periods, respectively. There was no cleared capacity in Bruce because no participant submitted offers into the auction. See section 3.2 of Chapter 4 for an in-depth discussion of the DR auction.

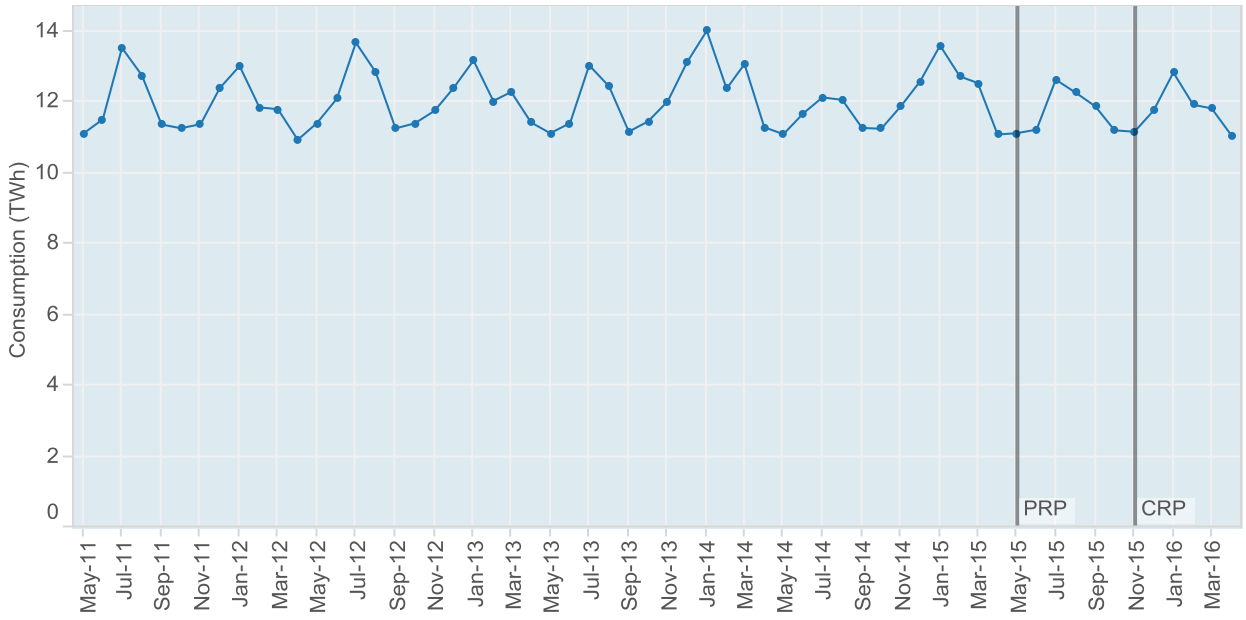
2 *Demand*

This section discusses Ontario energy demand for the Current Reporting Period relative to previous years.

Figure 2-20: Monthly Ontario Energy Demand
May 2011 – April 2016
(TWh)

Description:

Figure 2-20 presents energy consumption by all Ontario consumers in each month in the past 5 years. The figure represents Ontario demand, which includes demand satisfied by behind-the-meter (embedded) generators.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

Ontario monthly consumption information shows seasonal variations in consumption and year-to-year changes in consumption patterns.

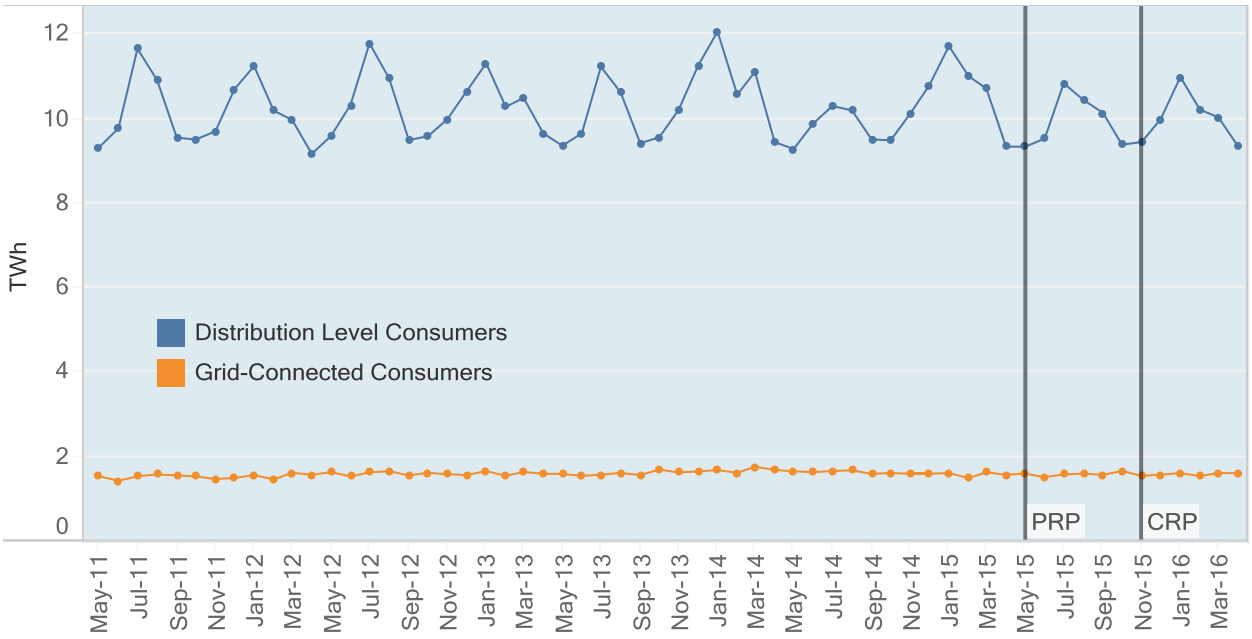
Commentary and Market Consideration:

The peak consumption during the Current Reporting Period was 12.82 TWh, which was lower than the peak consumption during the Winter 2015 and Winter 2014 Periods. In fact, monthly demand in the Current Reporting Period was less than it was for each corresponding month in the Winter 2015 Period. The relatively mild winter weather contributed to the reduction in demand.

Figure 2-21: Monthly Total Energy Withdrawals, Distributors and Wholesale Loads May 2011 – April 2016 (TWh)

Description:

Figure 2-21 charts the demand of two categories of consumers: market participants that are directly connected to the IESO-controlled grid other than distributors (Grid-Connected Consumers), and consumers connected to distribution systems (Distribution Level Consumers).



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

The breakdown of consumers into these two categories helps identify their respective monthly demand profiles.

Commentary and Market Consideration:

Seasonal changes in Ontario demand are attributed almost entirely to Distribution Level Consumers, which include residential, small and medium commercial, and small industrial loads. Demand from Grid-connected consumers, a group primarily composed of industrial loads and large commercial consumers, exhibit little of the seasonality evident of distribution-level consumption.

3 *Supply*[37]

During the fourth quarter of 2015 and the first quarter of 2016, 549.7 MW of nameplate generating capacity completed commissioning and was added to the IESO-controlled grid's total installed generator capacity. This new grid-connected capacity consisted of wind (409.7 MW) biomass (40 MW) and solar (100 MW) generation. At the end of the first quarter of 2016, grid

[37] For a more detailed examination of the medium-term supply capacity in Ontario, see the IESO's 18-month outlook, released in March 2016 and available at: http://www.ieso.ca/-/media/files/ieso/document-library/planning-forecasts/18-month-outlook/18-month-outlook--2016mar.zip

connected generation capacity totalled 35,731 MW, consisting of nuclear (12,978 MW), gas-fired (9,942 MW), hydroelectric (8,432 MW), wind (3,643 MW), biofuel (495 MW) and solar generation (240 MW)[38].

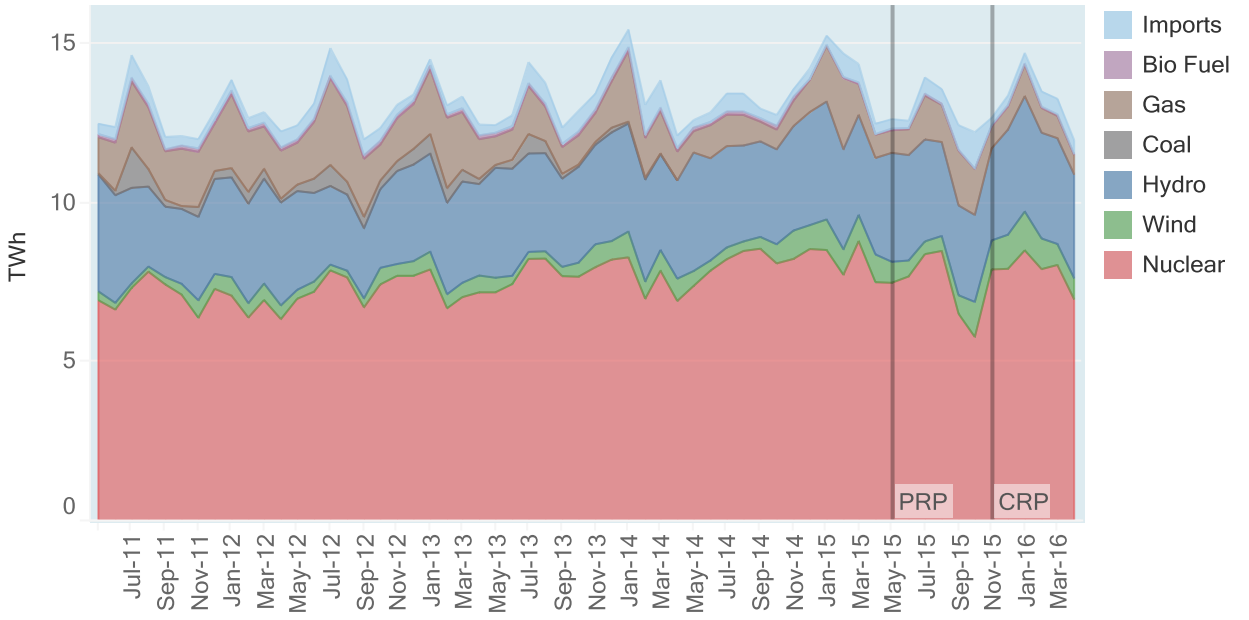
During the fourth quarter of 2015 and the first quarter of 2016, 130 MW of nameplate IESO contracted generating capacity was added at the distribution level. This new distribution-level capacity (or 'embedded' capacity) consisted of solar (110 MW), wind (14 MW), biofuel (1 MW), hydroelectric (5 MW), and gas-fired and combined heat and power (4 MW). At the end of the first quarter of 2016, IESO contracted embedded capacity totalled 2,970 MW, consisting of solar (1,876 MW), wind (498 MW), hydroelectric (269 MW), gas-fired and combined heat and power (213 MW), biofuel (108 MW) and energy from waste (10 MW).[39]

Figure 2-22: Resources Scheduled in the Real-Time Market (Unconstrained) Schedule by Reporting Period May 2011 – April 2016 (TWh)

Description:

Figure 2-22 illustrates the cumulative share of energy in the real-time unconstrained schedule for the past five years by resource or transaction type: wind, coal, gas-fired, hydroelectric, nuclear, and imports. Solar and biofuel are excluded from the figure as they contribute minimally to the total grid-connected resources scheduled in real-time.

[38] Capacity totals were obtained from the Ontario Energy Board's quarterly Ontario Energy Reports. Added capacity totals were calculated from 2015's Q1, Q2 and Q3 reports, which can be found at: http://www.ontarioenergyreport.ca/index.php
[39] Embedded capacity totals were obtained from the Ontario Energy Board's quarterly Ontario Energy Reports. Added embedded capacity totals were calculated from 2015's Q1, Q2 and Q3 reports, which can be found at: http://www.ontarioenergyreport.ca/index.php.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

This figure displays the evolution of Ontario's changing mix of real-time energy supply. Changes in the resources scheduled may be the result of a number of factors, such as changes in energy policy or seasonal variations (for example, during the spring snowmelt or 'freshet' when hydroelectric plants have an abundant supply of fuel).

Commentary and Market Considerations:

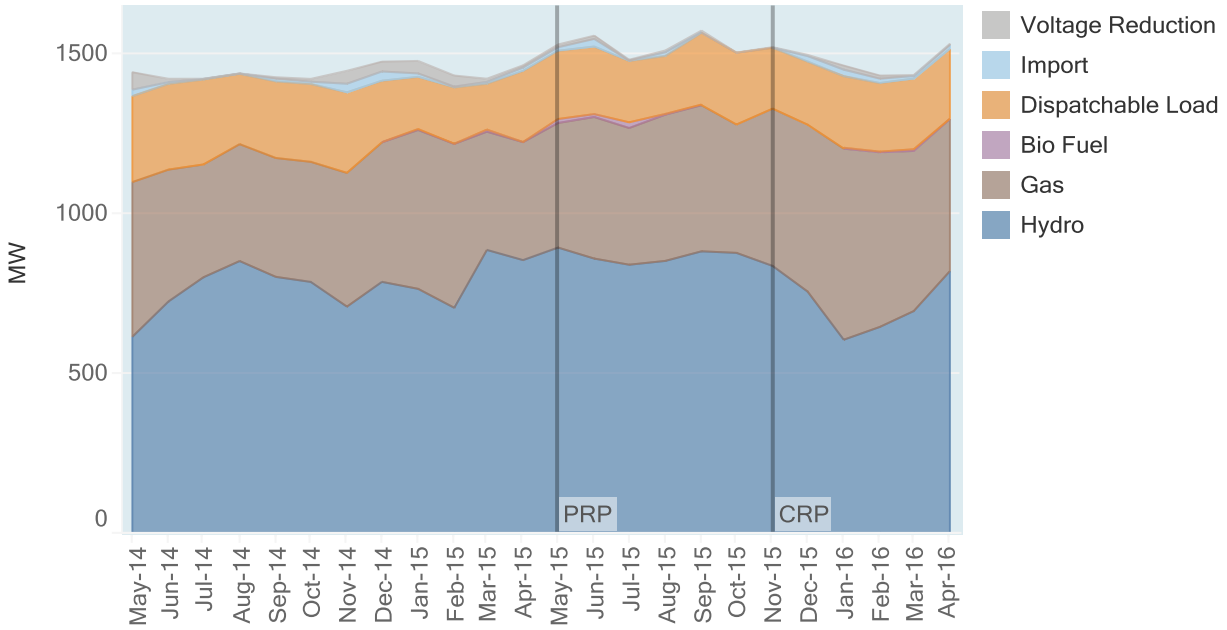
Nuclear and hydroelectric resources continued to be the main sources of generation in Ontario. Wind resources were scheduled to produce more than gas-fired facilities for the first time (5.5 TWh for wind, 4.5 TWh for gas) in the Current Reporting Period.

Figure 2-23: Average Hourly Operating Reserve Scheduled by Resource or Transaction Type May 2014 – April 2016 (MW per hour)

Description:

Figure 2-23 plots the average hourly amount of OR in the unconstrained schedule for the past two years by resource or transaction type: hydroelectric, gas-fired, imports, dispatchable loads

and voltage reduction.[40] Changes in the total average hourly operating reserve scheduled reflect changes in the OR quantity requirements.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

This figure reflects the evolution in Ontario's changing mix for OR supply as well as changes in the OR requirement over time. Changes in scheduled OR may result from a variety of factors such as changes in energy policy or seasonal variations, while changes to the OR requirement may result from changes in grid configuration and outages, among other factors. [41]

Commentary and Market Considerations:

The amount of OR scheduled in the Current Reporting Period (6.4 TWh) decreased relative to the Previous Reporting Period (6.7 TWh) but slightly increased relative to the 2015 Winter Period (6.3 TWh): this corresponded to changes in the total OR requirement between monitoring periods. Factors such as increased power flows on a major 500 kV circuit – connecting supply in the Northeast to demand in the South – and an instance of nuclear commissioning tests in April

[40] The IESO inserts standing offers in the OR offer stack that represent the IESO's ability to use 3% and 5% voltage reductions or forego the 30-minute OR requirement (under specific conditions) to meet OR needs. The offers have a pre-defined price and quantity and are only used in real-time, never in pre-dispatch. Voltage reduction is an out-of-market control action taken by the IESO when the market cannot provide enough supply to meet forecasted demand and reserve requirements.
[41] The total energy available from the 10-minute OR market must be enough to cover the single largest contingency in Ontario's electricity grid, with at least 25% of that energy available as 10-minute spinning reserve. The total energy available from the 30-minute OR market must be enough to cover half the second largest contingency on Ontario's grid.

2016 have contributed to the total OR requirement increasing beyond 1500 MW for more than 50% of all hours in the Current Reporting Period. In contrast, the Previous Reporting Period had approximately 90% of all such hours: this is likely attributed to seasonal freshet that increased the flow of hydroelectric power from the Northeast during May and June 2015. Between the Winter 2015 Period and Current Reporting Period, the slight increase in total OR requirement is likely attributed to anticipated changes in the operational profile of various nuclear facilities – a notable example being the nuclear commissioning tests that took place in April 2016.

The share of OR provided by hydro went down to an average of 48.9% during the Current Reporting Period compared to 56.8% from the Previous Reporting Period and 54.0% from the Winter 2015 Period. The share of OR provided by gas went up to 35.4% compared to 28.1% from the Previous Reporting Period and 30.0% from the Winter 2015 Period. The remainder of OR were supplied by voltage reduction, dispatchable loads, and imports.

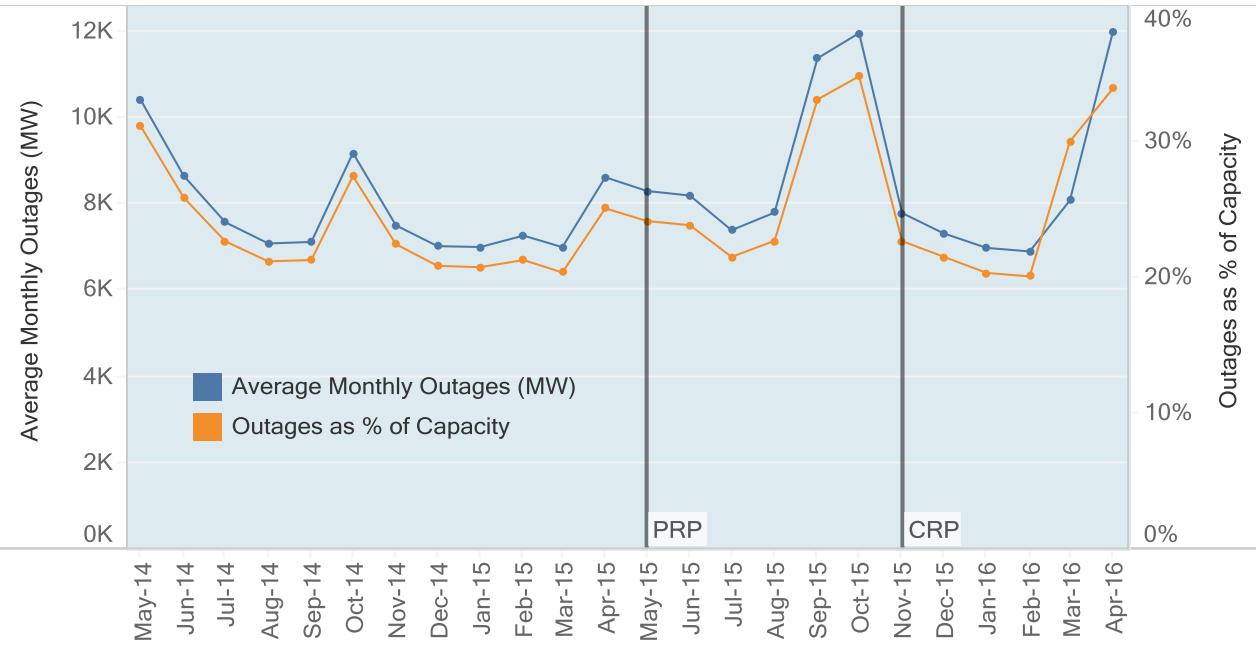
Figure 2-24: Unavailable Generation Relative to Installed Capacity
May 2014 – April 2016
(% of capacity) [42]

Description:

Figure 2-24 plots the monthly averages of the hourly sums of unavailable generation capacity due to planned and forced (i.e. unforeseen) outages and derates, along with unscheduled capacity from intermittent, self-scheduling and transitional generators and constrained generation capacity due to operating security limits, as a percentage of total grid-connected installed generation capacity from May 2014 – April 2016.[43]

[42] In Previous Panel Reports, Figure 1-24 reported planned and forced outages and derates relative to capacity. The Panel has decided to report on all unavailable generation capacity. As such, the data reported in Figure 1-24 will not align with similar data published in previous Panel Reports for the period of November 2013 through April 2015. The Panel did this intentionally as it has revised the methodology by which it reports on unavailable generation capacity to also include unscheduled capacity from self-scheduling resources and capacity that is made unavailable due to security limits on the high-voltage grid, in addition to planned and forced outages and derates.

[43] Unavailable generation capacity data was obtained from System Status Reports published daily by the IESO. A simple monthly average was calculated using the most recently reported totals for each hour of each trade date. Daily, weekly and monthly market summaries published by the IESO can be found here: http://www.ieso.ca/Pages/Power-Data/Market-Summaries-Archive.aspx.



*PRP: Previous Reporting Period. CRP: Current Reporting Period

Relevance:

Statistics regarding unavailable generation capacity provide an overview of how much of the time facilities in the province were able to provide supply, a key factor in the determination of market prices.

Commentary and Market Considerations:

Until March and April 2016, average monthly outages had decreased significantly from the Previous Reporting Period. The spike in outages in March and April are primarily attributed to nuclear refurbishments and refueling procedures that accounted for 65% of all unavailable capacity. Furthermore, planned outages with hydroelectric generation stations, for reasons such as transmission upgrades, accounted for 24% of all unavailable capacity.

4 *Imports, Exports and Net Exports*

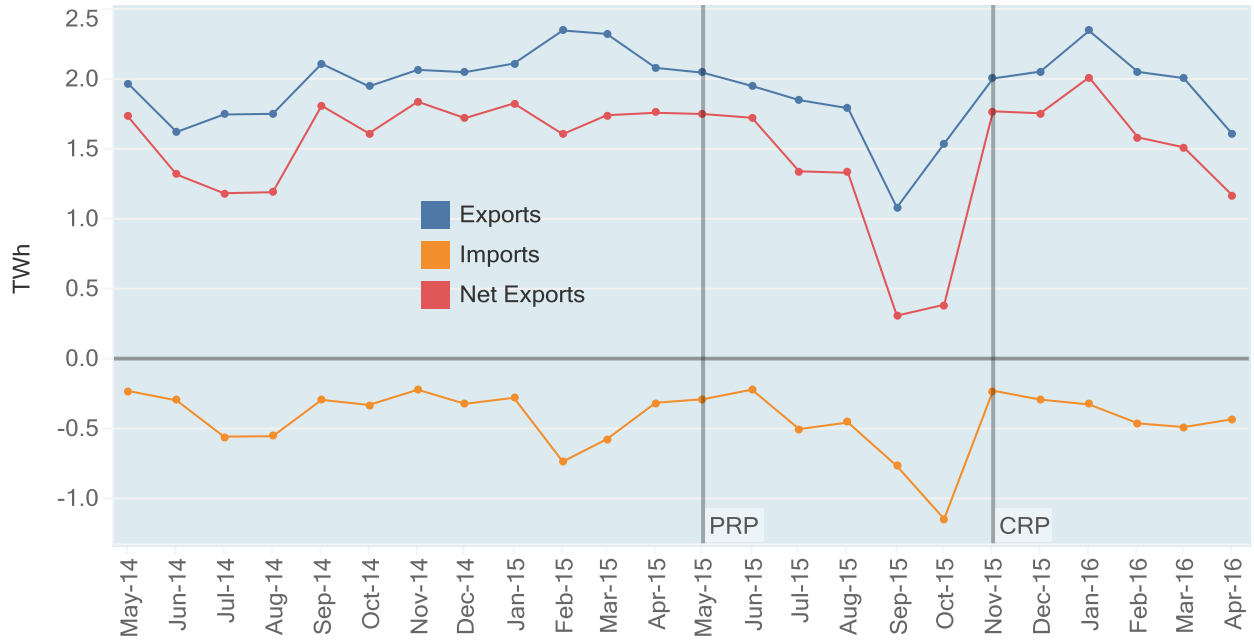
The data used in this section are based on the unconstrained schedules as these directly affect market prices. The unconstrained schedules may not reflect actual power flows.[44]

[44] Although the constrained schedules provide a better picture of actual flows of power on the interties, they do not provide information on intertie congestion prices or the Ontario uniform price (either in pre-dispatch or in real-time).

Figure 2-25: Total Monthly Imports, Exports & Net Exports (Unconstrained Schedule) May 2014 – April 2016 (TWh)

Description:

Figure 2-25 plots total monthly energy imports, exports and net exports from May 2014 to April 2016. Exports are represented by positive values while imports are represented by negative values.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

Imports and exports play an important role in determining supply and demand conditions in the province, and thus affect the market price. Tracking net export transactions over time provides insight into supply and demand conditions in Ontario relative to neighbouring jurisdictions. Periods of sustained net exports, such as the Current Reporting Period, indicate times of relative energy surplus in Ontario, while sustained periods of net imports, such as during the mid-2000s, indicate periods of relative scarcity.

Commentary and Market Considerations:

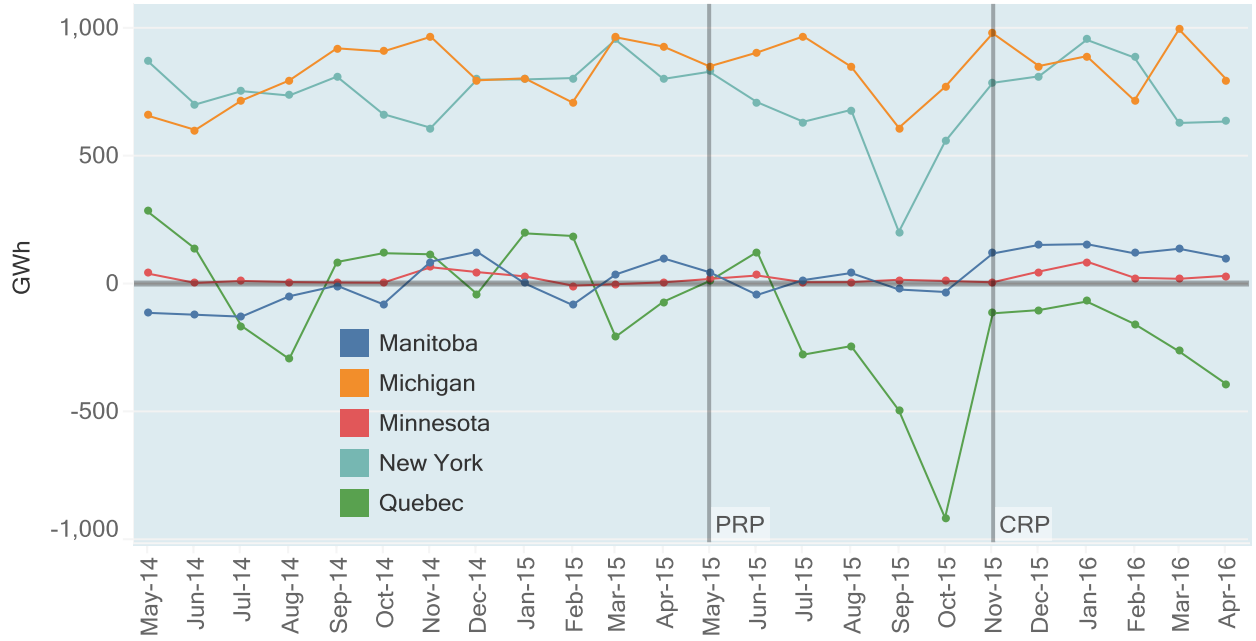
There were higher net exports in the Current Reporting Period, which totalled 9.76 TWh, compared to the previous reporting Period, which totalled 6.80 TWh. The combination of low

demand, low HOEP, and a weak Canadian dollar has contributed to stronger net exports.

Figure 2-26: Net Exports by Interface Group
May 2014 – April 2016
(GWh)

Description:

Figure 2-26 presents a breakdown of net energy exports from May 2014 to April 2016 to each of Ontario's five neighbouring jurisdictions: Manitoba, Michigan, Minnesota, New York and Quebec. Net exports are represented by positive values while net imports are represented by negative values.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

This figure shows how Ontario's energy trade evolves over time with each external jurisdiction.

Commentary and Market Considerations:

Net exports increased in every interface (except Québec) compared to previous monitoring periods, which was incentivized by the lower Ontario HOEP in the Current Reporting Period. The New York intertie experienced the largest increase in net exports by 1.09 TWh. While Québec's net imports dropped by 0.69 TWh in the Current Reporting Period, it remained a net importer across all months, totalling 1.11 TWh.

Table 2-7: Average Monthly Export Failures by Interface Group and Cause May 2015 – October 2015 & November 2015 – April 2016 (GWh and %)

Interface Group	Average Monthly Exports GWh		Average Monthly Export Failure and Curtailment GWh				Export Failure and Curtailment Rate %			
			ISO-Curtailment		MP-Failure		ISO-Curtailment		MP-Failure	
	Current	Previous	Current	Previous	Current	Previous	Current	Previous	Current	Previous
New York	386.3	289.1	1.8	1.5	8.3	5.9	0.5	0.5	2.1	2.0
Michigan	348.1	333.8	1.5	1.2	3.2	4.7	0.4	0.4	0.9	1.4
Manitoba	79.9	37.4	2.6	3.2	16.3	11.7	3.2	8.5	20.4	31.1
Minnesota	6.0	8.2	0.2	0.4	0.2	0.2	2.7	5.0	3.7	2.9
Quebec	93.2	92.5	4.2	1.4	1.3	0.4	4.5	1.5	1.4	0.4

Description:

Table 2-6 reports average monthly export curtailments and failures over the Current and Previous Reporting Periods by interface group and cause. The failure and curtailment rates are expressed as a percentage of total (constrained) exports over each interface, excluding linked wheel transactions.[45]

Relevance:

Curtailment (ISO Curtailment) refers to an action taken by a system operator, typically for reliability or security reasons. Failure (MP Failure), on the other hand, refers to a transaction that fails due to a failure on the part of a market participant (such as a failure to obtain transmission service).

MP Failures and ISO Curtailments in respect of exports reduce demand between the hour-ahead pre-dispatch schedule and real-time. These short-notice changes in demand can lead to a sub-optimal level of intertie transactions given the market prices that prevail in real-time, and may contribute to SBG conditions. The IESO may dispatch down domestic generation or curtail imports to compensate for MP Failures or ISO Curtailments.

[45] A linked wheel transaction is one in which an import and an export are scheduled in the same hour, thus wheeling energy through Ontario.

Commentary and Market Considerations:

Average export failures caused by market participants increased in volume on the Manitoba intertie; such failures accounted for 20% of export transactions. Manitoba continues to be an outlier with respect to the percentage and absolute volume of monthly exports that are curtailed due to MP failure.

Table 2-8: Average Monthly Import Failures by Interface Group and Cause May 2015 – October 2015 & November 2015 – April 2016 (GWh and %)

Interface Group	Average Monthly Imports GWh		Average Monthly Import Failure and Curtailment GWh				Import Failure and Curtailment Rate %			
			ISO-Curtailment		MP-Failure		ISO-Curtailment		MP-Failure	
	Current	Previous	Current	Previous	Current	Previous	Current	Previous	Current	Previous
New York	1.4	13.1	0.0	0.1	0.1	0.4	0.6	0.6	3.8	3.0
Michigan	1.2	5.4	0.2	0.1	0.4	0.6	16.6	1.6	34.7	10.4
Manitoba	34.8	21.0	5.9	3.5	0.3	0.1	16.9	16.8	0.8	0.5
Minnesota	8.2	1.4	0.9	0.1	0.7	0.1	11.5	4.9	8.8	4.2
Quebec	85.7	136.1	2.6	5.9	0.1	0.5	3.1	4.3	0.1	0.3

Description:

Table 2-7 reports average monthly import failures and curtailments over the Current and Previous Reporting Periods by interface group and cause. The MP Failure and ISO Curtailment rates are expressed as a percentage of total imports, excluding linked wheel transactions.

Relevance:

MP Failures and ISO Curtailments in respect of imports represent a reduction in supply between the hour-ahead pre-dispatch schedule and real-time. This change in supply can lead to a sub-optimal level of intertie transactions and may contribute to increases in price. The IESO may dispatch up domestic generation or curtail exports to compensate for MP Failures and ISO Curtailments.

Commentary and Market Considerations:

Except Québec, the percentage of ISO Curtailments and MP Failures increased at all interfaces relative to the Previous Reporting Period, albeit on a relatively low volume of imports

Chapter 3: Analysis of Anomalous Market Outcomes

1 *Introduction*

This chapter examines the market outcomes associated with anomalous prices and payments during the Current Reporting Period, from November 1, 2015 to April 30, 2016.

Typically, the Panel's analysis of anomalous events focusses on high and negative Hourly Ontario Energy Prices (HOEP), as well as instances of high uplift, such as Congestion Management Settlement Credit (CMSC) payments, Intertie Offer Guarantee (IOG) payments, and payments made through the IESO's Real-Time Generation Cost Guarantee (RT-GCG) program and the Day-Ahead Commitment Program (DACP). Payments made through the DACP are referred to as Day-Ahead Production Cost Guarantee (DA-PCG) payments. All of the aforementioned payments are recovered from consumers through uplift charges.

In the past, the Panel has defined anomalous events using several thresholds, such as the HOEP being greater than $200/MWh or daily CMSC payments being in excess of $1 million. Table 3-1 displays the number of events that exceeded the Panel's thresholds during the Current Reporting Period.

Table 3-1: Summary of Anomalous Events
November 2015 – April 2016
(Number of Events)

Anomalous Event Threshold	Number of Events
HOEP > $200	5
HOEP ≤ $0	1,427
Energy CMSC > $1 million/day	0
Energy CMSC > $500,000/hour	0
OR Payments > $100,000/hour	5
IOG > $1 million/day	0
IOG > $500,000/hour	0

During the Current Reporting Period, there were five hours when the HOEP was greater than $200/MWh; during these five hours there were also operating reserve (OR) payments in excess of $100,000. Having analyzed these hours, the Panel has concluded that they were largely the result of variable generation shortfall and demand forecast errors. In these hours, ample supply

conditions in pre-dispatch resulted in relatively low prices and few gas-fired facilities being committed to generate. With few gas-fired facilities online to provide relatively inexpensive ramping capability and OR, the system had limited ability to absorb the loss of variable generation and excess demand in real time, resulting in high HOEP and OR payments. High prices related to limited ramp capability were examined in detail in the Panel's November 2016 Monitoring Report.[46] In one of the five aforementioned hours, the supply shortfall and excess demand conditions were exacerbated by an unforeseen nuclear outage.

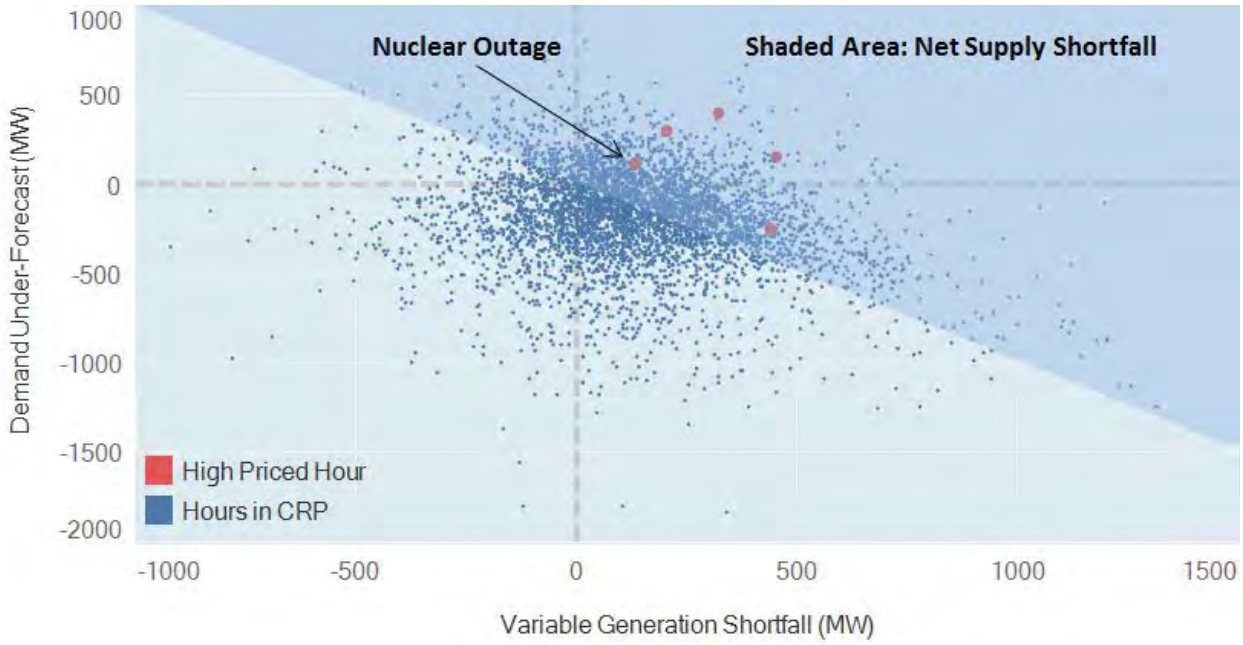
There were no days or hours during the Current Reporting Period that exceeded the Panel's CMSC or IOG thresholds.

There were 1,427 hours when HOEP was non-positive: an all-time high number of non-positive hours during a 6-month reporting period. Non-positive HOEPs are the result of increasingly common conditions, such as: low Ontario demand, abundant supply offered at negative prices, and failed export transactions, among other causes. The Panel examines the conditions surrounding non-positive hours in greater detail in section 3 of this chapter.

As has been described above, a high or low price, or a large uplift payment, does not necessarily indicate that there was something amiss; the regularity with which variable generation shortfall and/or demand under-forecast are contributors to high HOEP events is one such example. Figure 3-1 shows that all five high price hours in the Current Reporting Period, marked in red, occurred during net supply shortfall (defined as hours in which the sum of demand under-forecast and variable generation shortfall are positive, creating tighter supply conditions in real-time relative to pre-dispatch).

[46] See pages 69 –71 of the Panel's November 2016 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2015-Oct2015_20161117.pdf

Figure 3-1: HOEP by Net Supply Conditions
November 2015 – April 2016
(MW)



Anomalous events (market outcomes that fall outside predicted patterns and norms) do not necessarily result in high prices or large uplift payments, nor are they necessarily confined to a single hour or day. In this chapter, the Panel has expanded its analysis of anomalous events beyond those which meet or exceed pre-determined thresholds. Other criteria for assessing events include: the appropriateness of the market outcome relative to the Market Objective[47] and the Market Rules; the novelty and frequency of an unexpected event, as well as the relevance of the outcome to current IESO initiatives and stakeholder engagements. The Panel's approach will be informed by the historic thresholds, but will broaden the analysis to include other relevant events as appropriate.

2 *Analysis of Anomalous Events*

In the sections that follow, the Panel reports on three anomalous events that occurred during the Current Reporting Period. These events resulted in inappropriate payments or outcomes related to: dispatchable loads in the OR markets, ramp-down CMSC payments, and export failures.

[47] The Market Objective of the IESO-administered markets is to promote an efficient, competitive, and reliable market for the wholesale sale and purchase of electricity and ancillary services in Ontario.

2.1 *Dispatchable Loads and Unavailable Operating Reserves in February 2016*

Relevance

From January 2010 to April 2016, the Panel estimates that dispatchable loads (DLs) received approximately $12.5 million in OR payments for reserves that they were incapable of providing. Such instances are of concern, not only for the significant inappropriate payments themselves, but also for the corresponding reliability issues. To highlight these concerns, the Panel analyzes one such event that occurred in the ten-minute OR markets during hour ending (HE) 19 on February 21, 2016.

Analysis

OR is standby capacity intended to respond to, and recover from, a contingency on the grid. Such a contingency could take the form of a sudden, unexpected increase in demand, a forced outage of generation or transmission equipment, or significant dispatch deviations from generators or DLs, among other possibilities. Resources scheduled to provide standby capacity in the ten-minute OR market must provide the entirety of that capacity within ten minutes of receiving an OR activation, and must be able to provide the activated capacity for at least one hour.[48] When a DL's standby capacity is activated to help recover from a contingency, the DL provides relief by reducing its consumption. To be able to provide the required relief (and fulfill its OR activation), a DL must be consuming at least the activation amount prior to being activated.

Table 3-2 summarizes the dispatch schedules, actual MW consumption, OR price, and corresponding OR payments for two DLs on HE 19 of February 21, 2016.

[48] Refer to the Market Rules, Chapter 5 Appendices, Section 1.2

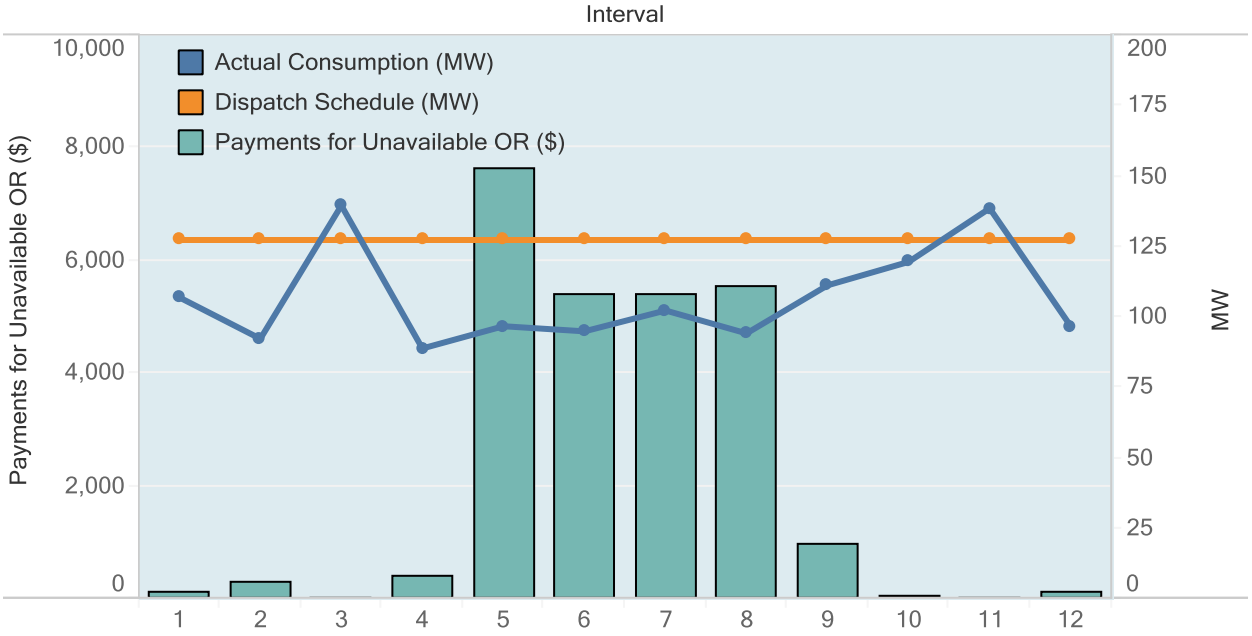
Table 3-2: Participation of Two Dispatchable Loads in the Ten-Minute OR Markets
February 21, 2016, HE 19

Interval	OR Schedule (MW)	Actual Consumption (MW)	Unavailable OR (MW)[49]	OR Price ($/MWh)	Payment for Unavailable OR ($)
1	127	107	36	30	91
2	127	92	43	75	270
3	127	139	0	91	0
4	127	89	48	96	386
5	127	96	46	2,000	7,613
6	127	95	32	2,000	5,403
7	127	102	32	2,000	5,386
8	127	94	33	2,000	5,523
9	127	111	29	396	956
10	127	119	16	30	39
11	127	138	0	30	0
12	127	96	37	30	93
Total	-	-	-	-	**25,760**

As illustrated in Figure 3-2, during numerous intervals within the hour these DLs consumed less than their scheduled OR standby capacity. Had these DLs been activated to recover from a contingency, they would have been unable to provide the relief they were paid for.

[49] Because Table 3-2 aggregates the data of two DLs, the unavailable OR in a given interval is not necessarily equal to the difference between the total OR schedule and the total consumption shown in the table. The OR schedule represents the maximum OR a DL can provide, therefore any over consumption by one DL does not offset the under consumption of another when determining how much OR is available.

Figure 3-2: OR Schedule, Energy Consumption, and Excess Compensation for Two Dispatchable Loads on February 21, 2016, HE 19 (MW, $)



In totality these resources were compensated for 29 MWh[50] of OR they were unable to provide. This hour experienced the highest average ten-minute OR price of the Current Reporting Period ($1,050/MW), signalling a premium on reliability. Since DLs are compensated according to their OR schedule, not the OR they were able to provide, the two DLs received $25,760 for OR that they were incapable of providing.

DLs scheduled for ten-minute OR were capable of providing the entirety of their OR schedule in only 9.6% of intervals during the Current Reporting Period. In the remaining 90.4% of intervals, DLs had an average OR schedule of 122 MW, but only consumed an average of 57 MW. Accordingly, there was an average of 65 MW of unavailable OR from DLs, or approximately 6.5% of the average ten-minute OR requirement. This outcome is inappropriate: not only were the DLs potentially compromising the reliability of the grid by operating in a manner which rendered them unable to meet their OR obligation, but they were compensated for such behaviour. This is a recurring outcome (across several DLs) that has resulted in approximately

[50] This number is calculated by adding the unavailable OR values in each interval from Table 3-2 and dividing the sum by 12 to generate the corresponding MWh value.

$12.5 million being paid for scheduled OR that were not actually provided (from January 2010 through April 2016).

The Panel recognizes that provisions exist in the Market Rules to recover payments made to DLs for unavailable OR. While the Panel encourages the IESO to pursue any and all available avenues for recovering such payments, the IESO should also pursue a more fundamental solution that prevents the payments from being made in the first instance.

Recommendation 3-1:

The IESO should take steps to ensure that dispatchable loads are only compensated for the amount of operating reserve they were capable of providing in real-time. More fundamentally, the IESO should explore options for ensuring unavailable OR is not scheduled in the first instance.

2.2 *Ramp-Down CMSC Payments for a Gas-Fired Generator on January 4, 2016*

Relevance

A generator signals its intent to come offline at the end of its run by raising its energy offer price above the local nodal price, thus becoming uneconomic in the constrained sequence. Due to the three-times ramp rate assumption used in the unconstrained sequence,[51] a generator's unconstrained schedule ramps down faster than its constrained schedule. As a result, there is a divergence between the two schedules during the ramp-down period, resulting in constrained-on CMSC payments.

In past reports, the Panel has highlighted the inappropriate nature of CMSC payments caused by ramping, and recommended that the IESO eliminate them; CMSC is not intended to provide a revenue stream for generators that take a voluntary action.

The IESO conducted a stakeholder engagement on the matter, introducing Market Rule Amendment MR-00414 to mitigate CMSC payments caused by ramping. While the rule was

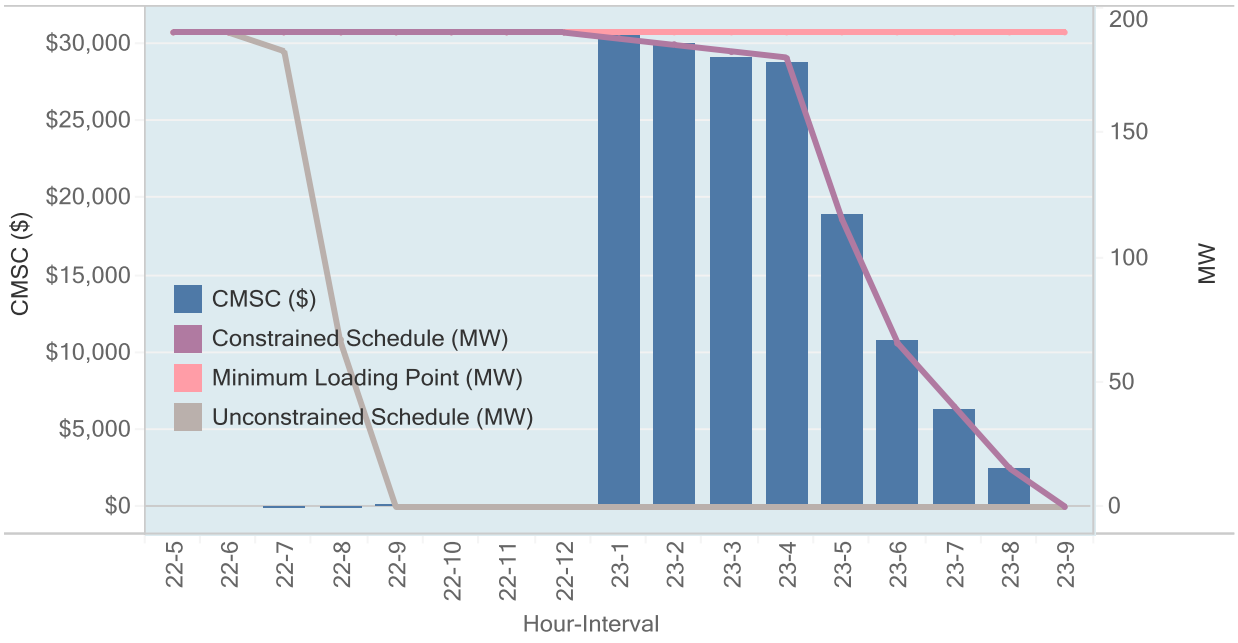
[51] The "three-times ramp rate assumption" refers to the IESO's unconstrained dispatch algorithm's assumption that a generator can ramp down three times faster than is technically feasible. The constrained dispatch algorithm must respect the physical limitations of generators in order to produce a feasible schedule, and thus does not employ the three-times ramp rate assumption. The result is a divergence between a generator's constrained and unconstrained schedules any time the unit is ramping, which results in CMSC payments.

approved by the IESO Board of Directors on June 24, 2015,[52] it was not implemented by the IESO until a year and half later on December 8, 2016. To highlight the ramp-down CMSC payments that were ongoing during the period between the rule approval and its implementation, the following section examines the operation of a gas-fired facility in January 2016.

Analysis

On January 4, 2016, a gas-fired facility offered its full capacity at $2,000/MWh in HE 23 in order to signal its intent to ramp down and come offline. As illustrated in Figure 2-3, the facility ramped down from interval 1 to 8 in HE 23 and generated approximately $160,000 in CMSC payments.

Figure 3-3: Gas-Fired Generator's Ramp-Down Profile and CMSC
January 4, 2016
(MW, $)



The CMSC payments were self-induced by the market participant's decision to come offline and exacerbated by the participant's choice of a $2,000/MWh offer price; which was well in excess of the price required to ensure a ramp down was achieved.

[52] For more information on Market Rule 414, see the IESO's SE-111 stakeholder webpage, available at: http://www.iemo.com/Pages/Participate/Stakeholder-Engagement/SE-111.aspx

While the IESO Board of Directors had already approved a Market Rule to limit ramp-down CMSC payments, the effective date of the Market Rule was contingent on the implementation of the required IT system changes, which were not yet in place.[53] Had the rule been put in effect when passed, ramp-down CMSC payments for the gas-fired facility would have been reduced from $160,000 to $4,000.

The Panel estimates that CMSC payments caused by ramping would have been reduced by $1.9 million market wide from June 25, 2015 to December 7, 2016 had the Market Rule amendment been effective from the date the amendment was approved.

The Panel understands that the implementation of the Market Rule amendment was delayed due to the relative complexity of the required solution. The decision not to make the market rule amendment effective immediately or to recommend retroactive adjustment was also due to the intricacy of the IT solutions. The Panel recognizes that while the implementation of the Market Rule amendment represented a complex IT process, that relative difficulty should not preclude the IESO from making retroactive adjustments pursuant to the appropriate Market Rule, which in this case could have clawed back approximately $1.9 million.

The Panel believes that the IESO should make all reasonable efforts to allow future Market Rule amendments to be effective immediately upon approval by the Board of Directors. This would allow the IESO to retroactively apply adjustments in accordance with the Market Rules, regardless of implementation constraints.

2.3 *Export Failures on the New York Intertie on February 20, 2016*

Relevance

Transmission lines can only accommodate a certain amount of electricity flow at a given time; this limit is referred to as the scheduling limit. Congestion occurs when the quantity of electricity scheduled to flow over the transmission line exceeds the scheduling limit.

When an intertie becomes congested, the Intertie Zonal Price (IZP) – the price at which intertie traders are settled – will differ from the Market Clearing Price (MCP). The IZP will be higher

[53] For more information on the IESO Board of Directors decision on MR-00414, see the Market Rule Amendment Proposal, available: http://www.ieso.ca/Documents/Amend/mr2015/MR_00414_R00_Amendment_Proposal_Ramp_Down_CMSC_v5.0.pdf , page 1

than the MCP when there is export congestion and lower than the MCP when there is import congestion. This produces a situation in which either side of the same transaction is settled at different prices: the intertie transaction is settled at the IZP, while the corresponding domestic transaction is settled at the MCP.[54] The difference in the money collected from the buyer and paid to the seller is referred to as congestion rent.

Intertie congestion can be difficult to predict and can significantly impact the profitability of an intertie transaction; congestion introduces financial risk to intertie traders. Accordingly, the IESO auctions off Transmission Rights (TRs), which provide a financial hedge against congestion by paying out the difference between the IZP and the MCP when the intertie is congested.

TR payments are based on the level of intertie congestion in pre-dispatch, whereas congestion rent is based on the amount of energy dispatched an hour later in real-time. Intertie traders contribute to congestion, and thus TR payments, when they are scheduled in pre-dispatch.

After pre-dispatch but before real-time, an intertie trader may fail a scheduled transaction for reasons within its control, in which case the transaction does not flow and no congestion rent is collected. The result is TR payments (based on conditions anticipated in pre-dispatch) in excess of congestion rents collected (based on real-time conditions). TR payments in excess of congestion rent collected are referred to as a "congestion rent shortfall"; the shortfall is funded by diverting auction revenues from transmission customers to TR owners. As discussed in Chapter 4, this transfer of funds from transmission customers to TR owners is inappropriate and ultimately to the detriment of Ontario consumers.

The IESO may levy an intertie failure charge on intertie traders that fail transactions for reasons within their control. The amount of the failure charge, if any, is calculated pursuant to a pre-set formula and that only take into account the impact of the failure on the MCP.[55] The failure

[54] For instance, an exporter pays the IZP, while the Ontario generator that supplies that export is paid the MCP. In the case of export congestion, the exporter pays the higher IZP and the Ontario generator is paid the lower MCP: the difference in payments accrues as congestion rent. For more information on congestion rent, see section 3.1.1 of Chapter 4.
[55] The intertie failure charge is calculated on the basis of the spread between the pre-dispatch and real-time Ontario MCP multiplied by the number of failed megawatts.

charge does not capture the impact of the congestion rent shortfall that the failure creates.[56] Consequently, when there is congestion on the intertie, the failure charge is incommensurate with the congestion rent shortfall the failure created, leaving Ontario consumers to pay for the shortfall.[57]

From January 2010 to April 2016, the Panel estimates that intertie failures within the control of market participants have resulted in congestion rent shortfalls of approximately $11 million. To highlight this behaviour, the Panel examines an exporter's activity at the New York intertie on February 20, 2016.

Analysis

On February 20, 2016, an intertie trader bid to export 400 MW from Ontario to New York in every hour of the day, with an average weighted hourly bid price of $33.98/MWh. Pre-dispatch prices were below $5/MWh in all hours of the day, so the intertie trader's exports were continually economic, resulting in a total daily pre-dispatch export schedule of 9,600 MWh. However, following pre-dispatch but before real-time, the intertie trader failed a total of 7,456 MWh (78%) of its exports from Ontario to New York. These export failures were within the intertie trader's control, resulting from the participant's failure to economically schedule the corresponding import transactions in the New York electricity market. The intertie trader was subject to export failure charges totalling $466.

In 10 of the 22 hours when the intertie trader failed an export transaction, the New York intertie was export congested, with an average intertie congestion price of $3.51/MWh. By failing its export transactions throughout the day, the intertie trader contributed to higher congestion prices and greater TR payments, but avoided paying congestion rents, leaving Ontario consumers to pay for the shortfall.

In this particular instance, the intertie trader who failed the exports also owned 400 MW of New York export TRs, meaning it was the beneficiary of the congestion it helped create. All told, the

[56] Export failure on the intertie could result in other impacts unaccounted for by the failure charge, such as the need to constrain off domestic generation. In particular, export failures can exacerbate surplus baseload generation conditions and could potentially lead to costly nuclear maneuvers.
[57] Not accounting for congestion rent shortfall in the failure charge may incent traders that own TRs to create congestion in order to receive TR payments, only to intentionally fail its transactions and avoid paying congestion rents.

intertie trader paid $1,537 in congestion rent, but collected $14,044 in TR payments, for a total profit to the intertie trader (and congestion rent shortfall to the Ontario consumer) of $12,507.

Table 3-3: Intertie Trader's Activities during Hours with Intertie Congestion
February 20, 2016

Export Congestion Hour	Exports Scheduled in Pre-Dispatch (MW)	Exports Flowed in Real-Time (MW)	Congestion Rents Paid ($)	TR Payments Received ($)	Benefit to Intertie Trader (Congestion Rent Shortfall) ($)
1	400	57	163	1,144	981
2	400	164	800	1,952	1,152
4	400	0	0	1,200	1,200
6	400	38	114	1,200	1,086
10	400	0	0	104	104
11	400	0	0	3,000	3,000
15	400	0	0	404	404
17	400	0	0	1,600	1,600
22	400	200	460	920	460
23	400	0	0	2,520	2,520
Total	**4,000**	**459**	**1,537**	**14,044**	**12,507**

From January 2010 to April 2016, Ontario consumers have paid for approximately $11 million in congestion rent shortfall induced by intertie failures within the participant's control. This outcome is clearly inappropriate.

The Panel recognizes that the IESO has the authority within the Market Rules to adjust settlement amounts attributable to intertie failures within the market participant's control. While the Panel encourages the IESO to pursue any appropriate actions available to it via the Market Rules, it suggests that the IESO should also pursue a more fundamental solution that prevents situations like the one described above from occurring in the first instance. The Panel believes an appropriate failure charge should include congestion rents avoided.[58]

[58] In 2005, the IESO's Intertie Transaction Failure Working Group considered such an approach to calculating the intertie failure charge, but ultimately recommended the current methodology. In consideration of publicly available materials on the views and concerns of the working group and stakeholders at that time, the Panel found no compelling reason not to include the congestion rents avoided.

Recommendation 3-2:

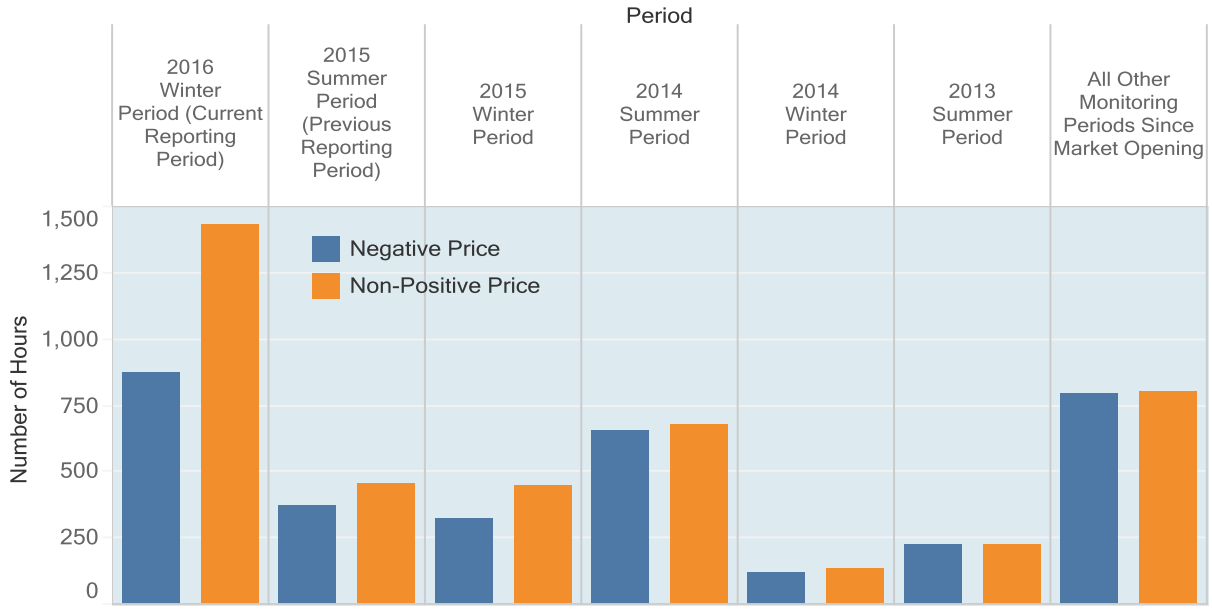
The IESO should revise the methodology used to set the intertie failure charge to include the congestion rents that an intertie trader avoids when it fails a scheduled transaction for reasons within its control.

2.4 *Examination of Non-Positive Price Hours*

The Panel has traditionally monitored low price hours when the HOEP is negative as a means to identify and report on potentially anomalous market outcomes. In recent reporting periods, there has been a significant increase in the frequency of zero-price HOEPs; the Panel has therefore altered its monitoring threshold to be non-positive HOEPs. Non-positive price hours typically signal an abundance of supply relative to demand, with contributing factors that include: low Ontario demand, failed export transactions, and an abundance of supply offered at non-positive prices.

During the Current Reporting Period there were 1,427 non-positive HOEPs, a significant increase from the corresponding period in the previous year when there were 447. As illustrated in Figure 3-4, the Current Reporting Period had the highest occurrence of non-positive HOEPs of all reporting periods since market opening; approximately 33% of all HOEPS during the Current Reporting Period were non-positive.

Figure 3-4: Non-Positive HOEPs by Reporting Period (Number of Hours)

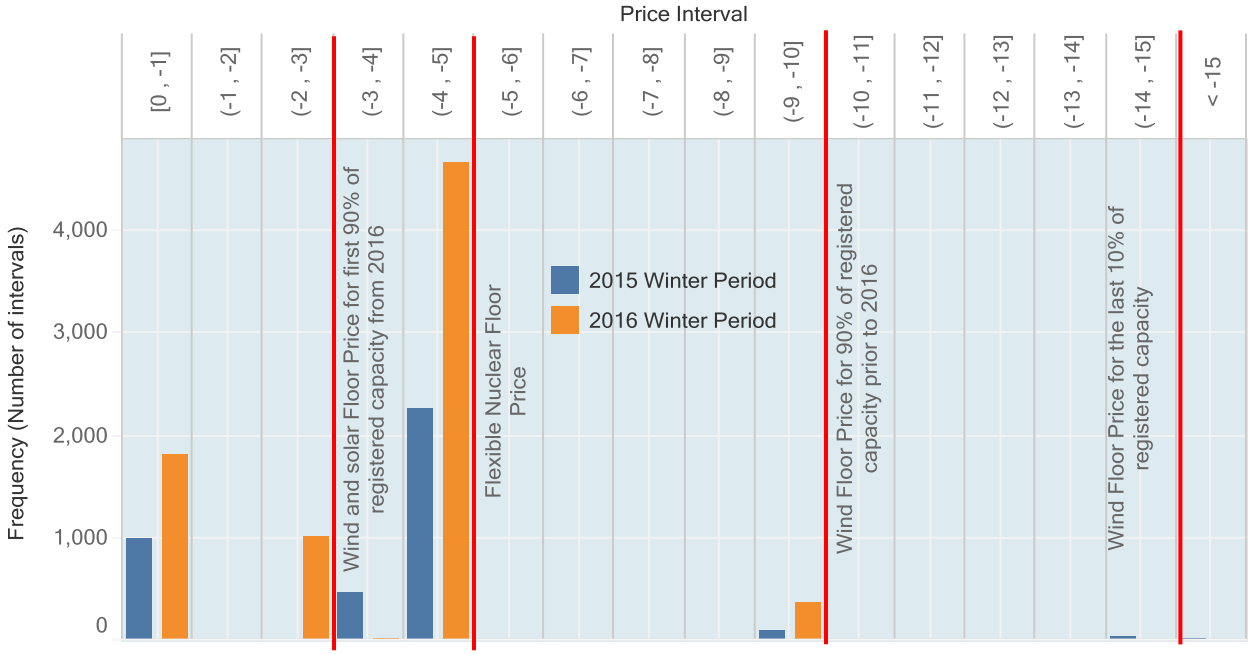


Non-positive HOEPs are prominent during periods of relatively low market demand, such as the early morning prior to 8:00 am or the late evenings after 10:00 pm. While non-positive HOEPs are particularly prevalent during weekends, they are becoming increasingly prominent during weekdays as well.

Figure 3-5 illustrates the frequency distribution for non-positive MCP's during the Current Reporting Period and the 2015 Winter Period, across $1/MWh price increments. The red vertical lines indicate the offer price floors imposed by the Market Rules for various resource types[59]. The price intervals demarcated by the offer price floors present the frequency with which certain resources go unscheduled in the unconstrained sequence. For example, any intervals to the right of the Flexible Nuclear Floor Price line indicate how often (375 intervals in the 2016 Winter Period) flexible nuclear went unscheduled in the Current Reporting Period.

[59] For more information on the offer price floors, see Market Manual 4 Part 4.2: Submission of Dispatch Data in the Real-Time Energy and OR Markets, available at: http://www.ieso.ca/Sector%20Participants/Market%20Operations/-/media/67f665f95aa94954b4a1d4504c772460.ashx

Figure 3-5: Frequency Distribution of Non-Positive MCPs
November 2015 – April 2015 & November 2015 – April 2016
(Number of Intervals)[60]



The unprecedented frequency of non-positive prices reflects consistent surplus baseload generation. This is in line with expectations given relatively stable demand and the changes in Ontario's underlying supply mix. On September 27, 2016, the Minister of Energy directed the suspension of the IESO's second round of the Large Renewable Procurement (LRP II) process, citing Ontario's strong supply situation. LRP II had targeted the procurement of up to 600 MW of wind and 250 MW of solar, among other renewable resources. Reducing the amount of future grid-connected baseload capacity should help mitigate additional downward pressure on market prices. However, the Panel notes that according to the Ontario Planning Outlook (OPO), there is an additional 1,050 MW of wind and solar to be installed by 2017 (1,500 MW by 2020).[61] The Panel expects the addition of these low marginal cost resources will further suppress market prices.

[60] On the horizontal axis of Figure 2-5, a square bracket indicates the number beside it is included in the MCP range while a round bracket indicates the number beside it is excluded.
[61] For more information on the Ontario supply outlook, see Module 4 of the Ontario Planning Outlook, available at: http://www.ieso.ca/-/media/files/ieso/document-library/planning-forecasts/ontario-planning-outlook/module-4-supply-outlook-20160901-pdf.pdf?la=en

Chapter 4: Matters to Report in the Ontario Electricity Marketplace

1 Introduction

In this chapter, the Panel presents its analysis of two aspects of the IESO-administered markets. The Panel's analysis considers the results and implications of the IESO's Demand Response Auction and examines disbursements made from the IESO's Transmission Rights (TR) Clearing Account.

2 Panel Investigations

The Panel may conduct an investigation into the conduct of market participants, including in relation to inappropriate or anomalous market conduct, when it considers such an investigation is warranted. The Panel currently has one gaming investigation under way in relation to a generator.

3 New Matters

3.1 Improving the Allocation of Disbursements from the Transmission Rights Clearing Account

Exporters have disproportionately benefited from disbursements from the TR Clearing Account, to the detriment of Ontario transmission customers. This disproportionate benefit is the result of the allocation methodology currently used to disburse funds from the account, and has resulted in $51 million being paid to exporters that the Panel believes ought to have been paid to Ontario transmission customers. Given the ongoing and material nature of the issue, future transfers will be significant if the current disbursement allocation methodology continues.

In support of an alternate disbursement allocation methodology, the sections that follow provide an overview of Ontario's intertie pricing system, the TR market and the IESO's administration of the TR Clearing Account. The sections conclude with a recommendation to the IESO to revise the disbursement methodology to what the Panel considers to be a fairer allocation.

3.1.1 Overview of the Transmission Rights Market and Clearing Account

Intertie Congestion and Congestion Pricing

Ontario's wholesale electricity market employs a uniform price design in which Ontario consumers and producers buy and sell electricity at the same price province-wide: this price is known as the Market Clearing Price (MCP). The uniform price design does not apply to the interties that connect Ontario to its neighbouring jurisdictions; exporters and importers pay, or

are paid, the relevant Intertie Zonal Price (IZP). The IZP differs from the MCP when there is congestion on the intertie. When there is no congestion the IZP is equal to the MCP.

Transmission lines can only accommodate a certain amount of electricity flow at a given time; this limit is referred to as the scheduling limit. Congestion occurs when the quantity of electricity scheduled to flow over the transmission line exceeds the scheduling limit.

When intertie traders collectively offer to buy or sell a net quantity[62] of economic imports or exports that exceeds the scheduling limit of the intertie, the intertie becomes congested. Under such circumstances there are more economic transactions on offer than there is transmission capacity, and the IESO must determine which transactions are scheduled and which are not: this is done through economic selection.

The IESO's dispatch algorithm schedules transactions based on their economic merit: from low-cost to high-cost for importers, and from high-price to low-price for exporters.[63] Transactions are scheduled in this manner until the intertie's scheduling limit is reached, or until there are no further economic transactions. In doing so the algorithm looks to maximize the gains from trade.

If intertie traders, on a net basis, offer to sell imported electricity to Ontario at a cost below the MCP and in excess of the intertie's scheduling limit, the intertie becomes import congested. Under such circumstances there is an oversupply of electricity at the intertie: this abundance is reflected in an IZP that is less than the MCP.

Import Congestion = Intertie Zonal Price < Market Clearing Price

If intertie traders, on a net basis, bid to buy and export electricity from Ontario at a price above the MCP and in excess of the intertie's scheduling limit, the intertie becomes export congested. Under such circumstances there is excess demand for electricity at the intertie: this scarcity is reflected in an IZP that is greater than the MCP.

Export Congestion = Intertie Zonal Price > Market Clearing Price

[62] Interties are scheduled on a net basis, meaning gross import transactions can exceed the scheduling limit if there are offsetting exports scheduled in the opposite direction, and vice versa. Net imports (or net exports) cannot exceed the scheduling limit.
[63] For example, an importer willing to sell electricity to Ontario at $20/MWh is scheduled ahead of an importer willing to sell at $30/MWh. Conversely, an exporter willing to buy electricity from Ontario at $50/MWh is scheduled ahead of an exporter willing to pay $40/MWh.

Congestion Rents

Importers are paid the IZP and exporters pay the IZP, which as discussed above, is higher or lower than the MCP when there is intertie congestion. This produces a situation in which either side of the same transaction is settled at different prices: the intertie transaction is settled at the IZP, while the corresponding domestic transaction is settled at the MCP. For instance, an exporter from Ontario pays the IZP, while the Ontario generator that supplies that export is paid the MCP. Likewise, an import into Ontario is paid the IZP, while the corresponding Ontario consumer pays the MCP. The difference in the money collected from the buyer and paid to the seller is referred to as congestion rent. Total congestion rent at a given intertie for a given hour is equal to the difference in prices multiplied by the net electricity flow in that direction.

Import Congestion Rent = (MCP – IZP) * Net Import Schedule
Export Congestion Rent = (IZP – MCP) * Net Export Schedule

Congestion rent reflects the value of scarce transmission capacity. The more valuable access to a transmission path is to those who wish to utilize it, the higher the congestion rent collected. Given intertie traders are willing to pay for scarce transmission capacity in the form of congestion rent, it follows that the owner of transmission capacity would benefit from making that transmission capacity available.

There are five companies which own and operate transmission lines in Ontario. Each of those five companies is subject to rate regulation by the Ontario Energy Board (OEB) which approves the rates they charge to their transmission customers. The regulated rates are derived from the revenue requirements of the companies, which is the revenue level at which they recover their costs including a return on equity.[64] Any congestion rent collected by the IESO and paid to transmission owners would go to offset the revenue requirement of those companies, thus reducing the regulated rates charged to their transmission customers. It follows that, in Ontario, transmission customers benefit from congestion rent.

[64] For a brief overview of the OEB's role in energy sector regulation and rate setting, see its Backgrounder on Energy Sector Regulation, at available at: http://www.ontarioenergyboard.ca/oeb/_Documents/Documents/Energy_Sector_Regulation-Overview.pdf

Transmission Rights

As explained above, the price intertie traders are settled at (the IZP) differs from the uniform Ontario price (the MCP) when there is intertie congestion. Intertie congestion can be difficult to predict and can significantly impact the profitability of an intertie transaction; congestion introduces financial risk to intertie traders. In order to provide the opportunity to hedge against that risk, the IESO operates a TR market.

TRs provide a financial hedge against price differences between the IZP and the MCP. The IESO offers an array of different TRs at monthly and quarterly auctions. The IESO auctions TRs by the megawatt, with each TR being specific to an intertie, a trade direction (import or export) and a length of time (1-month or 1-year). For example, a prospective exporter looking to hedge against congestion risk may purchase a TR for the New York intertie, in the export direction, that is valid for April 2017.

The owner of a one megawatt TR is entitled to a payment equal to the difference between the IZP and MCP every time there is congestion on the relevant intertie, in the relevant direction, and during the relevant time period:

> When import congested, the Import TR Payment = (MCP – IZP) * Import TRs owned
> When export congested, the Export TR Payment = (IZP – MCP) * Export TRs owned

Extending the New York export TR example from above, the owner of 100 MWs of the aforementioned TRs would receive a TR payment of $1,500 under the following conditions:

> MCP = $30/MWh
> IZP = $45/MWh
> Export TRs Owned = 100 MW
> TR Payment = (IZP – MCP) * Export TRs Owned
> TR Payment = ($45 – $30) * 100
> TR Payment = $1,500

The exporter, who pays $4,500 to purchase 100 MW at the $45/MWh IZP, receives a $1,500 TR payment. The TR payment makes the net cost of the export $3,000; equivalent to having purchased 100 MW at the $30/MWh MCP. Effectively, an intertie trader that hedges their

transaction with TRs ensures that they can purchase power at the MCP, as opposed to the IZP, regardless of whether or not there is congestion.

TR payments are designed as a full hedge against congestion rents; accordingly, TR payments and congestion rents collected should be approximately equal. By purchasing a TR, the owner has essentially purchased the right to the congestion rents on that intertie.

Transmission Rights Auction Revenues

By selling TRs the IESO transfers the benefit of congestion rents from transmission customers to the purchasers of TRs. In return for relinquishing that benefit, transmission customers receive the proceeds generated from the sale of TRs; these proceeds are known as "auction revenues". If transmission customers did not receive TR auction revenues then, in the Panel's view, they would be made worse off by the IESO's sale of TRs.

Transmission Rights Clearing Account

The IESO administers Ontario's TR market and manages the flows of money through the TR Clearing Account. There are five flows of money into or out of the account, three credits and two debits:

Credits

- Congestion Rents
- Auction Revenues
- Interest accrued on funds in the account

Debits

- TR Payments
- Disbursements

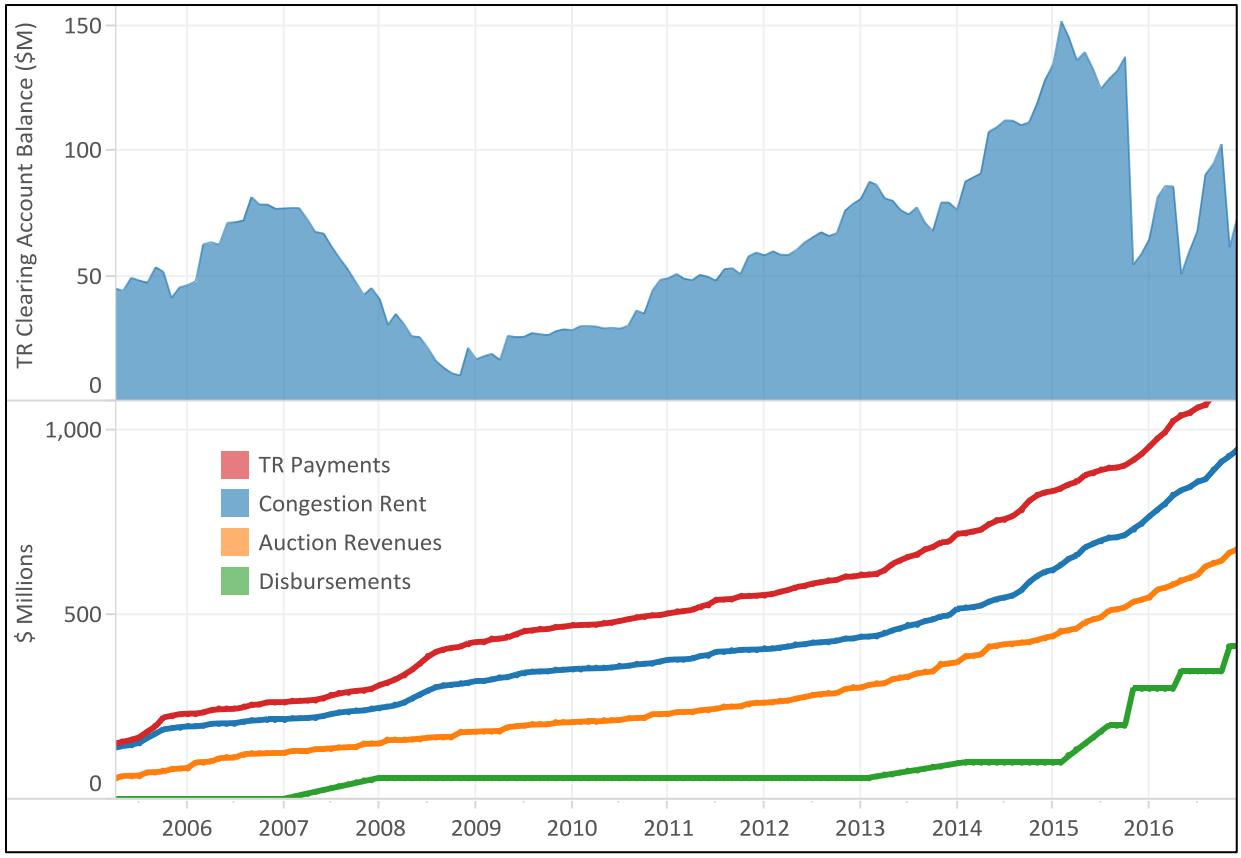
As discussed in the Transmission Rights section above, congestion rents and TR payments should be approximately equal, and thus offset one another in terms of the balance of the TR Clearing Account. The account's remaining credits, auction revenues and any accrued interest, are remitted to transmission customers through the disbursement debit transaction. It follows that, over time one would expect:

1) TR payments and congestion rents would be approximately equal, and

2) Auction revenues (plus interest) and disbursements would be approximately equal.

Figure 4-1 below shows the cumulative total of each of the TR Clearing Account's line items (excluding interest) since market opening, as well as the balance of the TR Clearing Account over time.

Figure 4-1: Transmission Rights Clearing Account Balance
May 2005 – December 2016
($ millions)



At the end of 2016, the TR Clearing Account had a balance of $74 million. For reasons discussed in the following section, neither of the aforementioned equalities materialized over time: TR

payments have exceeded congestion rents, and auction revenues have exceeded disbursements, both by significant margins.[65]

Disbursements from the Transmission Rights Clearing Account

The IESO Board of Directors (the "IESO Board") authorizes disbursements from the TR Clearing Account.[66] From market opening in May 2002, to the beginning of 2013, the IESO authorized one disbursement totalling $57 million; yet, had collected $302 million in auction revenues. Of the $245 million in undisbursed auction revenues, $85 million was in the TR Clearing Account at that time. The remaining $160 million had been paid to TR owners in order to fund TR payments in excess of congestion rents (see Figure 3-1). These excess TR payments represent money that could have been disbursed to transmission customers, but that was instead diverted to TR owners.

This considerable transfer from transmission customers to TR owners was primarily the result of an IESO Board decision in 2003. The decision permitted the IESO to intentionally over-sell TRs so that TR payments would exceed congestion rents collected, thus depleting the TR Clearing Account of auction revenues and paying them to TR owners.[67] In doing so, the IESO believed it was providing liquidity to the TR market and encouraging trade.

In its January 2013 Monitoring Report, the Panel examined the impacts of the IESO Board's decision and recommended a policy change. The Panel's proposed change would balance TR payments and congestion rents collected; stopping the transfer of funds to TR owners and allowing for all auction revenues to be disbursed to transmission customers.[68] The IESO adopted the Panel's recommendation and changed its policy; it is now in the process of implementing those changes.

[65] Further to the aforementioned equalities, one would expect that each of TR payments, congestion rents, auction revenues and disbursements would be approximately equal over time. Prospective TR owners should be willing to pay (in the form of auction revenues) the expected value of congestion rents for TRs; TR payments are intended to be a full hedge against congestion rents and should thus be equal to congestion rents; all auction revenues would be disbursed to transmission customers.
[66] See Chapter 8, Section 4.18.2 of the IESO's Market Rules, available at:
http://www.ieso.ca/Sector%20Participants/Market%20Operations/-/media/586603f319a04df9a08fcea9f8705b32.ashx
[67] For more information see the IESO's MR-00242 Market Rule Amendment Proposal, available at:
http://www.theimo.com/Documents/Amend/mr/mr_00242_Q00.pdf
[68] For more information see pages 146-161 of the Panel's January 2013 Monitoring Report, available at:
http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2011-Apr2012_20130114.pdf

In addition to the aforementioned policy change, the Panel recommended that the IESO disburse the funds in the TR Clearing Account at that time, as well as formalize a process for disbursing funds once annually.[69] In response to these recommendations the IESO disbursed $42 million to transmission customers in 2013, and formalized a process to review the balance in the account on a semi-annual basis to determine whether a disbursement should be made.[70] Since the Panel's 2013 recommendations, the IESO has disbursed $355 million from the TR Clearing Account to transmission customers.

3.1.2 Allocating Disbursements to Transmission Customers

Through a series of rules and definitions, the Market Rules dictate the methodology for disbursing funds from the TR Clearing Account.

> *Subject to section 4.18.3 [which establishes the TR Clearing Account reserve threshold], the IESO Board may, at such times as it determines appropriate, authorize the debit of funds from the TR clearing account for the purpose of using those funds to offset the transmission services charges referred to in section 3.6.3 of Chapter 9 [which references the disbursement formula].*[71] (emphasis added)

All consumers, both domestic and exporters, pay some form of transmission service charge, thus entitling them to disbursements under the Panel's reading of the above Market Rule.[72] While the rule establishes to whom and why disbursements are to be paid, it does not establish how much each transmission customer ought to receive.

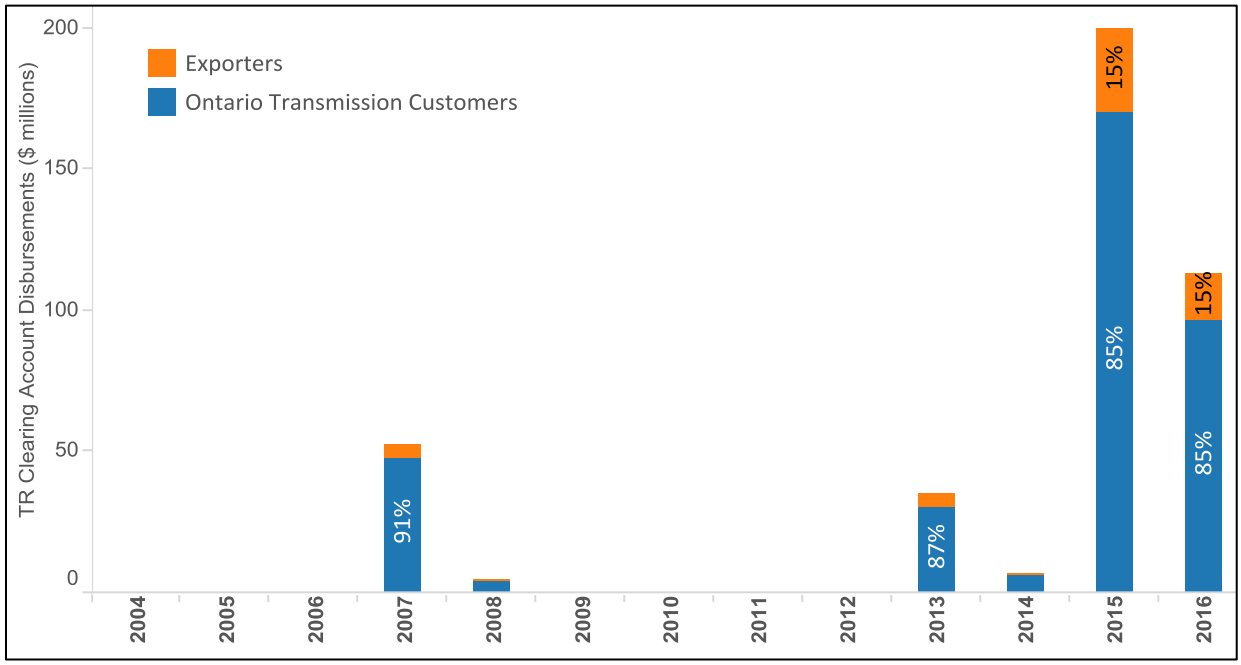
The formula for determining each transmission customer's share of disbursements from the TR Clearing Account is found in Chapter 9, Section 4.7 of the Market Rules. This formula dictates

[69] *Ibid.*
[70] For more information see the IESO's MR-00421 Market Rule Amendment Proposal, available at: http://www.ieso.ca/Documents/Amend/mr2015/MR_00421_TRCA_Amendment_Proposal%20v5_0.pdf
[71] See Chapter 8, Section 4.18.2 of the IESO's Market Rules, available at: http://www.ieso.ca/Sector%20Participants/Market%20Operations/-/media/586603f319a04df9a08fcea9f8705b32.ashx
[72] See the definition for "Transmission Service Charges" and "Transmission Services" in Chapter 10 of the IESO's Market Rules, available at: available at: http://www.ieso.ca/Sector%20Participants/Market%20Operations/-/media/4278d372760e4e719f78019aa2953c6e.ashx

that disbursements are proportionally allocated to consumers based on their share of total demand over the previous six months.[73]

Since market opening, the IESO Board has approved, and the IESO has made, six disbursements from the TR Clearing Account, totalling $412 million. These disbursements were allocated amongst Ontario transmission customers and exporters based on their proportion of demand over the month prior to disbursement, or six months in the case of the three most recent disbursements. Figure 4-2 displays disbursements to Ontario transmission customers and exporters by year from 2004 to 2016.

Figure 4-2: Disbursements from the TR Clearing Account
2004 – 2016
($ millions)



From 2004 to 2016, Ontario transmission customers received $354 million in disbursements from the TR Clearing Account (86% of total disbursements), while exporters received $58 million (14%).

[73] See Chapter 9, Section 4.7 of the IESO's Market Rules, available at: http://www.ieso.ca/Sector%20Participants/Market%20Operations/-/media/bfddf5699fdd4cce9fde8822336e747b.ashx.Earlier disbursements were allocated based on shares of total demand during the month prior to disbursement.

The decision to allocate disbursements based on shares of demand appears to date back to a Technical Panel decision in July of 2000. At that time, the Technical Panel was presented with a number of options for disbursing funds from the TR Clearing Account, including: disbursing funds to Ontario consumers only, exporters only, or both based on shares of demand. The Technical Panel ultimately endorsed disbursing funds based on shares of demand; this methodology was adopted for market opening and continues today. Unfortunately, the Technical Panel's rationale for selecting this option is not well-documented.

When the Panel assesses elements of market design, market rules or procedures, it considers the impacts of different options across various measures and principles. As dictated by its mandate, the Panel's primary considerations involve the impact on the efficient and fair operation of competitive markets.[74] While the Panel is not mandated to monitor or report on the reliability of the grid, it also considers potential reliability impacts when making its assessments.

In the Panel's assessment, there are no efficiency or reliability impacts associated with choosing one reasonable allocation methodology over another. In order for such impacts to occur, the real-time consumption decisions of market participants must be meaningfully influenced by disbursement considerations. For instance, under the current design an exporter could conceivably increase its trade activity in order to increase its share of disbursements. That said, any meaningful link between real-time consumption decisions and disbursement considerations is unlikely. Not only are future disbursements distant and unknown, but any additional disbursement revenue associated with increasing demand would most likely be far outweighed by the additional costs of the increased consumption. In other words, real-time incentives remain the driver of real-time behaviour, not disbursements.

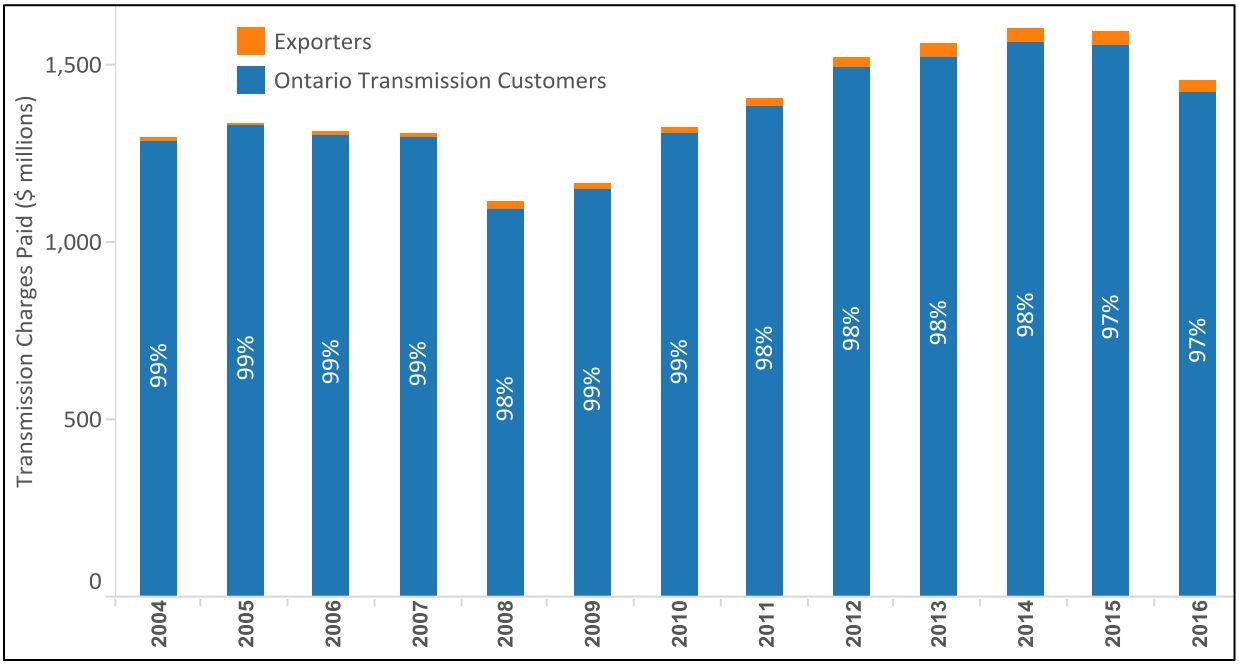
With no impact on efficiency or reliability, the Panel looked to its other mandated principle, namely fairness, to assess disbursement options. As stated in Chapter 8, Section 4.18.2 of the Market Rules, the purpose of disbursements from the TR Clearing Account is to offset transmission service charges; the disbursement is a rebate on costs paid. Accordingly, the Panel believes that a fair allocation would have each customer receive a rebate proportionate to its

[74] See the Ontario Energy Board's Bylaw #3, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/About%20the%20OEB/OEB_bylaw_3.pdf

share of costs paid. For instance, a transmission customer that paid 1% of the total transmission service charges over the accrual period would receive 1% of the disbursements at the end of that period. Unfortunately, the current allocation methodology has not resulted in what the Panel considers to be a fair allocation of disbursements.

Figure 4-3 displays the transmission service charges paid by Ontario transmission customers and exporters by year from 2004 to 2016.

Figure 4-3: Transmission Charges Paid
2004 – 2016
($ millions)



From 2004 to 2016, Ontario transmission customers paid $17.7 billion in transmission charges (98.3% of total charges), while exporters paid $304 million (1.7%). Despite paying 98.3% of total transmission charges, Ontario transmission customers received only 86% of disbursements from the TR Clearing Account (see Figure 3-3); exporters received 14% of disbursements despite paying only 1.7% of total transmission charges.

The misalignment stems from the fact that disbursements are allocated based on shares of demand, not shares of transmission service charges paid. The transmission charge associated with a megawatt-hour of Ontario demand is significantly higher than the transmission charge

associated with a megawatt-hour of export demand. As a result, exporters benefit disproportionately when disbursements are based on demand; such a methodology does not result in what the Panel considers to be a fair allocation.[75]

Had disbursements been allocated in line with the Panel's view on fairness, Ontario transmission customers would have received disbursements totalling $405 million while exporters would have received $7 million. Under such an allocation, Ontario transmission customers would have received an additional $51 million in disbursements that was actually paid to exporters.

Given the IESO's revised TR Clearing Account policies aimed at balancing congestion rents and TR payments, the Panel expects all future auction revenues to be disbursed to transmission customers. Since 2010, auction revenues have increased each year, eclipsing $100 million per year in 2015 and 2016. Left unremedied, the disbursement allocation methodology will continue to be a significant issue going forward.

Recommendation 4-1:

A. The IESO should revise the manner in which it allocates disbursements from the Transmission Rights Clearing Account such that disbursements are proportionate to transmission service charges paid over the relevant accrual period.

B. The IESO should not disburse any further funds from the Transmission Rights Clearing Account until such time that Recommendation 4-1(A) has been addressed.

3.2 *Assessment of the IESO's Demand Response Auction*

Since 2004, the Government of Ontario has been mandating the development of electricity conservation programs. The primary aim of these programs is to alleviate the need to build new generation facilities by reducing demand during peak periods.[76] Demand Response (DR) programs, which incent consumers to reduce consumption during periods of high prices, high demand or tight supply, have been a large part of that conservation effort.

[75] The transmission charges applicable to Ontario transmission customers are broken down into three separate OEB approved rates: Network Service Charge, Line Connection Service Charge and Transformation Connection Service Charge. Together these rates currently total $8.97/MWh. Exporters are subject to the Export Transmission Service (ETS) charge, which is currently set at $1.85/MWh. Both the rates charged to Ontario transmission customers and exporters are set annually and have varied over time, though the rates applicable to Ontario transmission customers have always been higher than the ETS charge.

[76] The Ministry of Energy's *Conservation First: A Renewed Vision for Energy Conservation in Ontario* report states that, "Ontario's vision is to invest in conservation first, before new generation, where cost-effective." The report is available at: http://www.energy.gov.on.ca/en/files/2013/07/conservation-first-en.pdf

The IESO is responsible for achieving the conservation related policy goals set forth by the Ministry of Energy. Prior to 2015, bilateral contracting was the primary means of procuring the necessary DR resources to meet policy objectives; in 2015, the IESO developed the DR auction. The DR auction introduced a competitive, flexible and transparent process for procuring DR resources, where formerly there was none.

The DR auction occurs once annually and procures DR resources for a period of one year. As part of the auction process eligible resources submit the quantity of DR capacity they are willing to provide, and the price at which they are willing to provide it; the IESO uses those offers to build a supply curve. The DR auction clearing price is set where the supply curve intersects the administratively determined demand curve; all resources selected in the DR auction receive the clearing price.[77] To be paid, resources procured through the DR auction must be made available to reduce consumption during specified periods, and must actually reduce consumption when certain activation criteria are met. For this service, resources procured in the 2016 and 2017 DR auctions will be paid up to a total of $73 million; these payments are recovered from Ontario consumers through an uplift charge.[78]

Two types of resources are permitted to participate in the DR auction: dispatchable loads and hourly demand response (HDR) resources. Dispatchable loads already participate in the energy market, changing their consumption in response to five-minute price signals; participating in the DR auction should not materially change the behaviour of these resources. For that reason, the following sections focus on HDR resources, unless otherwise stated. HDR resources are not willing or able to respond to five-minute price signals, and would not participate in the energy market absent some incentive, such as the payments received through the DR auction. To date, approximately 72% of all DR procured through the DR auction has been from HDR resources.

[77] Given the differences in supply and demand in different areas of the province, the IESO limits the amount of DR procured in each zone. If the limit is reached in a given zone, the clearing price in that zone may differ from the others.
[78] While auction payments are technically recovered from Ontario consumers via uplift, the uplift is allocated in the exact same manner as the Global Adjustment. In other words, a consumer's share of this uplift is based on whether they are Class A or Class B customers: Class A customers are charged based on their share of consumption during the five coincident peak demand hours during a year, Class B customers based on their volumetric consumption on all days. Exporters do not pay this uplift.

The IESO has stated that the DR auction is part of a suite of programs and incentives that will help meet the Ministry of Energy's conservation related policy goals.[79] However, for the reasons explained in this section, it is unlikely that the current DR program will actually contribute to conservation or demand reduction. Briefly, this is because the rules associated with the DR auction establish thresholds for activation which have not been realized to date and are unlikely to be realized in the future.

3.2.1 Meeting the Ministry of Energy's Policy Goal

Having said that, it is worth noting that the IESO views the DR auction as an initial step towards the evolution of capacity procurement in the province; one in which all generating and DR capacity is procured through an integrated auction.[80] The Panel supports this longer-term objective.

In 2013, the Ministry of Energy issued its most recent conservation related policy goal: use DR to meet 10% of peak demand by 2025 (approximately 2,400 MW under then forecasted conditions).[81] The IESO views the DR auction as a means of achieving the Ministry's policy goal:

> *Creating a DR auction will support the province's objective for DR to meet 10 per cent of Ontario's peak demand by 2025 and encourage new competitive DR resources to help meet that goal for Ontario's electricity system.*[82] – IESO

In order for the IESO's suite of DR programs and incentives to achieve peak demand reductions, DR not only needs to be available during periods of peak demand, but must also be activated during those periods. As such, it is important to understand the difference between the procurement of DR capacity (i.e. DR availability), and achieving peak demand reductions (i.e.

[79] See the IESO's *Demand Response Stakeholder Engagement Plan,* available at: http://www.ieso.ca/-/media/files/ieso/document-library/engage/dra/20140911-dr-auction_se-plan_draft.pdf?la=en
[80] For more information on the IESO's capacity auction development plans see slides 7 and 8 of its *Developing a Market Renewal Workplan* presentation, available at: http://www.ieso.ca/-/media/files/ieso/document-library/engage/me/me-20160419-developing-a-workplan.pdf?la=en
[81] For more information on the Ministry of Energy's policy goal see pages 20-27 of the *2013 Long Term Energy Plan* report, available at: http://www.energy.gov.on.ca/en/files/2014/10/LTEP_2013_English_WEB.pdf
[82] See the IESO's *Demand Response Stakeholder Engagement Plan,* available at: http://www.ieso.ca/-/media/files/ieso/document-library/engage/dra/20140911-dr-auction_se-plan_draft.pdf?la=en

DR activations). A program that procures DR capacity, but does not result in DR activations during peak demand, will not help achieve the Ministry of Energy's policy goal.

As currently designed, DR procured through the IESO's DR auction is unlikely to be activated during periods of peak demand. To understand why that is, it is necessary to understand both the availability obligation placed on DR resources and the criteria under which they are activated.

Availability Obligation

DR resources procured through the DR auction are required to participate in the energy market for certain pre-determined commitment periods and availability windows. The availability window applies to business days only: 12 PM to 9 PM from May to October (Summer Commitment Period) and 4 PM to 9 PM from November to April (Winter Commitment Period).

During the availability windows DR resources must enter bids into the energy market at prices between $100/MWh and $2,000/MWh. These bids represent the price at which the resource is willing to be activated for DR. The bids must be entered into the market before the IESO's day-ahead process starts, and remain in the market until the IESO determines the resource will not be activated, or until an activation is completed.

Activation Criteria

In order for a DR resource to be activated during the applicable availability window, it must receive both a standby notice and an activation notice from the IESO.

First, a DR resource will receive a standby notice at or before 7 AM if the pre-dispatch nodal price at its location is above its bid price for four consecutive hours within the availability window. Second, if the resource receives a standby notice, it may next receive an activation notice 2.5 hours prior to activation, so long as the price remains above its bid price for four consecutive hours within the availability window. If a DR resource receives an activation notice it must reduce its consumption for a period of four hours, beginning with the first hour included in the activation notice.

Consider the following example: a DR resource is procured for the Winter Commitment Period; to fulfill its availability obligation it bids $1,999/MWh into the energy market during all hours of

the availability window. For simplicity, assume that any activation will start at 4 PM and conclude at 8 PM.[83]

Under these conditions the DR resource will receive a standby notice if, during any of the hours before 7 AM, the pre-dispatch nodal prices for the 4 PM to 8 PM activation period exceed the resource's $1,999/MWh bid. To then receive an activation notice, the same conditions must persist at 1:30 PM, in which case the resource must reduce its consumption for the 4 PM to 8 PM activation period.

Prospect of Being Activated

Given the activation criteria described above, the likelihood of an activation is remote. This is borne out by events since the Current Reporting Period; since the first commitment period started in May 2016, no HDR resource has been activated.

Under the program rules DR resources can bid into the energy market at any price between $100/MWh and $2,000/MWh; the higher the bid price, the lower the likelihood of being activated. Table 4-1 contains the prices used to date by HDR resources when submitting their bids to the energy market.

Table 4-1: HDR Resources' Bids into the Energy Market
May 2016 – December 2016

Observed Bid Prices	HDR Capacity Bid at Observed Price
$1,999/MWh	82%
$500/MWh	18%

Since the start of the first commitment period 82% of all DR capacity has been bid into the energy market at the program's maximum allowable price. While the Panel supports DR resources being able to bid into the energy market at any price, bidding at the maximum allowable price, in conjunction with the current activation criteria, means that HDR resources will not be activated. Indeed, the Panel's analysis indicates that any bid price over $220/MWh would not have been activated during the period.

[83] During the Winter Commitment Period, a DR resource may also have an activation period from 5 PM to 9 PM. During the Summer Commitment Period an activation period may span any four consecutive hours between noon and 9 PM.

Given Ontario's current surplus supply conditions and the prices that persisted over the period, it is not surprising that there were no activations.

That said the province has not always been flush with surplus supply. In 2005 and 2006 all-time demand records were being set in Ontario, and in the winter of 2014 the "polar vortex" weather event increased demand and constrained supply. To get a sense of the likelihood of an activation given the current activation criteria, the Panel applied the same criteria to all hours dating back to the high demand conditions experienced in 2005. Table 4-2 displays the number of HDR activations that would have occurred at various bid prices since 2005.

Table 4-2: Hypothetical HDR Activations by Bid Price
2005 – 2016
(Number of Activations)

Energy Bid Price ($/MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
100 - 200	552	152	199	188	1	26	18	16	4	168	66	88
200 - 300	65	16	7	4	-	3	4	-	5	51	-	33
300 - 400	27	9	-	4	-	-	-	-	-	6	-	-
400 - 500	27	9	-	-	-	-	-	-	-	-	-	-
500 - 600	25	3	-	-	-	-	-	-	-	-	-	-
600 - 700	15	1	-	-	-	-	-	-	-	-	-	-
700 - 800	8	1	-	-	-	-	-	-	-	-	-	-
800 - 900	4	-	-	-	-	-	-	-	-	-	-	-
900 - 1,000	1	-	-	-	-	-	-	-	-	-	-	-
1,000+	-	-	-	-	-	-	-	-	-	-	-	-

Since 2005, no bid price above $1,000/MWh would have been activated, yet most HDR resources bid at twice that price. Any bid price over $400/MWh would not have been activated since 2006.[84]

Even under the most aggressive of demand projections, peak demand is not expected to return to record 2005 and 2006 levels until 2029.[85] Ontario is also in a better supply situation than it was during those years, having added thousands of megawatts of capacity to the grid.[86]

[84] Going forward, new HDR resources may emerge at different locations on the grid; their likelihood of activation may differ.
[85] See the IESO's most recent *Ontario Planning Outlook*, available at: http://www.ieso.ca/Documents/OPO/Ontario-Planning-Outlook-September2016.pdf
[86] See *The Need for Capacity* section below for a summary of Ontario's current supply and demand conditions.

The Panel is mindful that reducing consumption during periods of peak demand is a means to an end, and should not be a goal unto itself. A DR resource may wish to consume during periods of high demand, but may be incented to abstain in order to alleviate the need to build additional supply. In this way, DR programs incur short-term costs (i.e. curtailing otherwise efficient energy consumption) in order to avoid long-term costs (i.e. reducing the need for additional peak generation capacity). As long as the avoided long-term costs exceed the incurred short-term costs, reducing peak demand can be efficient.

Ontario is currently flush with supply, and will continue to be for the foreseeable future (see *The Need for Capacity* section below). Even with considerable demand growth, there is little need to build new capacity. Consequently, consumption during peak periods results in no additional long-term capacity costs, meaning demand reductions during these periods are unnecessary and likely inefficient. It follows that payments to procure DR, such as those provided by the DR auction, are also unnecessary and inefficient.

3.2.2 Meeting the IESO's Capacity Objective

As mentioned in the previous section, the IESO's DR auction is unlikely to provide energy through DR activations given the current activation criteria.

The notion that the DR auction is procuring capacity only is consistent with the program's availability obligations, as well as the manner in which DR resources are compensated. Specifically, DR resources are paid to be available for activation, not to be activated; there are no minimum requirements on the number of times a resource must be activated. In furtherance of this idea, the IESO plans to integrate the DR auction and its participants into the broader capacity auction currently being developed through the IESO's Market Renewal initiative.[87] In the sections that follow, the Panel assesses the appropriateness of the DR auction as a means to procure capacity.

[87] For more information on the IESO's capacity auction development plans see slides 7 and 8 of its *Developing a Market Renewal Workplan* presentation, available at: http://www.ieso.ca/-/media/files/ieso/document-library/engage/me/me-20160419-developing-a-workplan.pdf?la=en

Availability Obligation and Activation Criteria

Unlike meeting the Ministry of Energy's policy goal of using DR to reduce peak demand, procuring capacity does not necessarily come with the expectation that it will be utilised regularly or predictably. The IESO must procure enough capacity to ensure that Ontario's electricity needs are met, plus some additional capacity to ensure reliability. On that basis, one would expect there to be a portion of capacity that is rarely if ever used. Specifically, capacity resources with high bids in the energy market, such as those procured to date through the DR auction, are the last to be activated and are likely only needed on rare occasions. For DR capacity to be of use, the activation criteria needs to result in consumption reductions on those infrequent occasions when those resources are needed.

As noted earlier, HDR resources bidding at the maximum allowable energy market price (82% of all HDR resources to date) would not have been activated from 2005 onwards; resources bid above $400/MWh would not have been activated since 2006. There have been occasions since 2005, including during the very tight supply conditions experienced during the winter of 2014, when DR activations could have been beneficial.[88] To that end, the Panel encourages the IESO to assess whether changes to the current availability obligations and activation criteria should be made in order to facilitate activations when needed.

Technology-Specific Procurement

In terms of satisfying the need for capacity, capacity from DR is no different than capacity from other resources, such as gas-fired generators. Given the substitutability of capacity from different technologies, the procurement process should be technology neutral, not favouring one technology over another. Technological neutrality allows the procurement mechanism to select the lowest cost capacity, no matter the resource type. In order for the procurement mechanism to be technologically neutral it must permit all resources to compete against one another to supply capacity, and place identical obligations on all resources procured. The need for technology-neutral procurement was recently supported by the Minister of Energy, Glenn Thibeault:

[88] The Panel finds it instructive that, over the same period, there were numerous other DR programs with differing activation criteria that resulted in activations, including activations under the program the DR auction is effectively replacing.

> *Upon taking this office, I was interested to learn that our previous procurements were essentially segmented into "technology-specific" allotments. In this day and age, with the level of innovation, pace of technological change – as well as the clear benefit to ratepayers from competitively procured resources; it is essential that we begin moving towards more "technology-agnostic" procurements.*
>
> *Too often we have sought to impose strict requirements on the system operator. Rather, as we seek to undertake future procurements – we should be focused on outcomes, rather than contracting with specific technologies. Moving to become technology-agnostic will provide new opportunities for innovation and modernization. We must unleash the electricity sector and our system operator to find the appropriate mix to fulfil a capacity auction would ensure that ratepayers receive the best prices possible.*[89]
>
> ***
>
> *Allocating the precise mix of technology types has largely been arbitrary and led to suboptimal siting, uncompetitive prices and heightened community concerns.*[90]

The DR policy goal set by the Ministry of Energy in 2013 is technology specific, as was the IESO's corresponding procurement. Currently, DR is the only capacity procured through an auction process. By limiting competitive procurement to one resource type, the IESO is limiting its ability to procure capacity at least cost. Fortunately, the IESO is considering the introduction of a technology-neutral capacity market, allowing for DR resources to compete against other technologies to provide capacity at least cost in the future.

The Need for Capacity

The quantity of DR capacity procured through the DR auction is determined by the intersection of the participant-offered supply curve and the IESO determined demand curve. The demand curve sets the bounds for how much DR capacity will be procured at different prices, including the maximum quantity at the auction's lowest price, and the minimum quantity at its highest price.

[89] Speech delivered by Glenn Thibeault (Minister of Energy) to the Empire Club of Canada on November 28, 2016.
[90] Comments made by Glenn Thibeault following his speech to the Economic Club of Canada on February 24, 2017, as reported in the Globe and Mail's article: *Ontario Liberals Eye Electricity Market Overhaul to Lower Rates*, available at: http://www.theglobeandmail.com/news/ontario-liberals-eye-electricity-market-overhaul-to-lower-rates/article34128778/

The IESO sets the position of the demand curve (i.e. how much DR will be bought at different prices) by setting a target quantity and price for procuring DR capacity. Recall that prior to the auction, DR was procured through bilateral contracting; those legacy contracts expire at different times, the last of these expires in 2018.[91] For the first DR auction, the IESO set the target quantity equal to the capacity that was expiring under those legacy contracts.[92] The IESO set the target price equal to the agreed upon price in those expiring contracts. In effect, the quantity of DR procured for 2016, and the price at which it was procured, was largely determined by market conditions that prevailed when those legacy contracts were signed (upwards of five years prior in some cases).[93] The IESO plans to increase DR capacity targets in future auctions by 7% per year, with additional increases as more legacy DR contracts expire.[94] In the Panel's view, the procurement of capacity for future periods should not be based on administratively determined growth rates or the volume of contract expirations, but rather on a reasonable expectation of capacity needs during the commitment period.

Regardless of the procurement mechanism, the decision on how much capacity to procure, if any, should be directly tied to the need for capacity. The IESO recently assessed the long-term need for capacity in Ontario, noting the province's strong capacity position in its *Ontario Power Outlook* report, "Ontario will have sufficient resources to meet demand requirements generally over the next decade across all [demand] outlooks".[95] This assessment is consistent with the IESO's most recent *18-month Outlook*.[96] Indeed, even without the expected capacity contributions of resources procured through the DR auction,[97] Ontario has sufficient capacity to

[91] See slide 4 of the IESO's September 2016 presentation: *Update on Target Capacity and Commitment Period*, available at: http://www.ieso.ca/sector-participants/engagement-initiatives/working-groups/-/media/files/ieso/document-library/working-group/demand-response/DRWG-20160930-Update-on-Target-Capacity-and-Commitment-Period.pdf
[92] See page 3 of the IESO's approved Market Rule Amendment Proposal (MR-00416-R01), available at: http://ieso.ca/Documents/Amend/mr2015/MR_00416_R01_Amendment_Proposal%20v5.0.pdf
[93] See slide 10 of the Ontario Power Authority's April 2014 presentation: *Demand Response Programs in Ontario*, available at: http://www.ieso.ca/sector-participants/engagement-initiatives/working-groups/-/media/files/ieso/document-library/working-group/demand-response/drwg-20140403-DRWG-OPA-Presentation.pdf
[94] See slide 3 of the IESO's September 2016 presentation: *Update on Target Capacity and Commitment Period*, available at: http://www.ieso.ca/sector-participants/engagement-initiatives/working-groups/-/media/files/ieso/document-library/working-group/demand-response/DRWG-20160930-Update-on-Target-Capacity-and-Commitment-Period.pdf
[95] See page 11 of the IESO's *Ontario Power Outlook*, available at: http://www.ieso.ca/Documents/OPO/Ontario-Planning-Outlook-September2016.pdf
[96] See page ii of the IESO's *18-Month Outlook,* available at: http://www.ieso.ca/-/media/files/ieso/document-library/planning-forecasts/18-month-outlook/18monthoutlook_2016sep.pdf
[97] The IESO's target procurement capacity for the DR auction is 648 MW in 2018, growing to 1,246 MW in 2025. For more information see the IESO's September 2016 presentation: *Update on Target Capacity and Commitment Period*, available at:

meet its needs for many years. Based on the IESO's most aggressive demand outlook (plus a reserve margin), and without any contribution from the DR auction, Ontario has sufficient capacity to meet its capacity needs until 2021. Under the most conservative demand outlook, Ontario has sufficient capacity until 2025.

Accordingly, the IESO is procuring capacity through the DR auction at a time when capacity is not needed. This procurement comes at a significant cost: resources procured through the 2016 and 2017 DR auctions will be paid upwards of $73 million in total. Under the most aggressive of assumptions, additional capacity is not needed until 2021. Fortuitously, the technology-neutral capacity auction in development is expected to have its first capacity auction in 2020 to procure capacity for future years.[98] Not only is the technology-neutral capacity auction a more cost effective way to procure capacity, but the timing of its implementation aligns far better with Ontario's capacity needs. [99]

In this regard it is noteworthy that various other capacity procurement projects have been cancelled or scaled back in recent years, including round two of the Large Renewal Procurement process,[100] and rounds five and six of the Feed-In Tariff program.[101]

Recommendation 4-2:

The IESO should reassess the value provided by the capacity procured through its Demand Response auction in light of Ontario's surplus capacity conditions, as well as the stated preference of the government and the IESO (through its Market Renewal initiative) for technology-neutral procurement at least cost.

http://www.ieso.ca/sector-participants/engagement-initiatives/working-groups/-/media/files/ieso/document-library/working-group/demand-response/DRWG-20160930-Update-on-Target-Capacity-and-Commitment-Period.pdf

[98] See slide 44 of the Brattle Group's December 2016 presentation: *IESO Market Renewal Benefits Case: Preliminary Benefits Case Findings*, available at: http://ieso.ca/-/media/files/ieso/document-library/engage/me/me-20161219-preliminary-benefits.pdf?la=en

[99] As part of its reasoning for implementing the DR auction, the IESO stated the auction will, "Provide a stable transition [from bilateral DR contracts] that offers a learning opportunity for DR providers to be able to successfully compete in a full capacity auction." While that may be true, that learning opportunity comes at a cost that will well exceed $100 million, all the while providing little benefit. For more information on the IESO's justification for the DR auction, see its Market Rule Amendment Submission (MR-416-Q00), available at: http://www.ieso.ca/Documents/Amend/mr2015/MR-00416-Q00.pdf

[100] See the Minister of Energy's Letter to the IESO, dated September 27, 2016, available at: http://www.ieso.ca/-/media/files/ieso/document-library/ministerial-directives/2016/directive-lrpii-efwsop-20160927.pdf?la=en

[101] See the Minister of Energy's Letter to the IESO, dated December 16, 2016, available at: http://www.ieso.ca/-/media/files/ieso/document-library/ministerial-directives/2016/directive-nug-20161216.pdf?la=en

Exhibit "P"

OEB Market Surveillance Panel report dated February 2018

Exhibit "P"

to the Affidavit of Francois Tardif

Sworn before me on October 29, 2025, in accordance with O. Reg. 431/20,
Administering Oath or Declaration Remotely



Commissioner for Taking Affidavits
(or as may be)

October 29, 2025

Keith Edward Hickey, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.

Expires June 24, 2027.

Ontario Energy Board **Commission de l'énergie de l'Ontario**

Ontario

Market Surveillance Panel

Monitoring Report on the IESO-Administered Electricity Markets

for the period from
May 2016 – October 2016

February 2018

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Role of the Market Surveillance Panel

The Market Surveillance Panel (Panel) is a panel of the Ontario Energy Board. Its role is to monitor, investigate and report on activities related to – and behaviour in – the wholesale electricity markets administered by the Independent Electricity System Operator (IESO).

The Panel monitors, evaluates and analyzes activities related to the IESO-administered markets and the conduct of market participants to identify:

- inappropriate or anomalous conduct in the markets, including gaming and the abuse of market power;
- activities of the IESO that may have an impact on market efficiencies or effective competition;
- actual or potential design or other flaws and inefficiencies in the Market Rules and procedures; and
- actual or potential design or other flaws in the overall structure of the IESO-administered markets and assess consistency of that structure with the efficient and fair operation of a competitive market.

Market-related activities and market conduct may also be the subject of a more formal and targeted investigation by the Panel. To that end, the Panel has authority under the *Electricity Act, 1998* to compel testimony and the production of information.

The Panel reports on the results of its monitoring and investigations. The Panel does not have the legislative mandate to impose sanctions or other remedies in response to inappropriate conduct or market defects, but it does make recommendations for remedial action as it considers appropriate.

Executive Summary

This report of the Market Surveillance Panel (Panel) covers the six month period from May 1, 2016 to October 31, 2016 (Summer 2016 Period). Certain portions of this report, notably Chapters 1 and 3, discuss noteworthy issues that are not necessarily linked to events in the Summer 2016 Period. Except where otherwise noted, developments occurring after October 31, 2017 are not reflected in this report.

The report is divided into the following four chapters:

- Chapter 1: Market Developments and Status of Recent Panel Recommendations;
- Chapter 2: Market Outcomes;
- Chapter 3: Analysis of Anomalous Market Outcomes; and
- Chapter 4: Matters to Report in the Ontario Electricity Market Place

Immediately below is a summary of each chapter.

Chapter 1: Market Developments and Status of Recent Panel Recommendations

Chapter 1 provides an update on recent developments related to the IESO-administered markets and the Panel's comments on the Independent Electricity System Operator's (IESO) responses to the recommendations contained in the Panel's previous semi-annual report.

The most significant development in the IESO-administered markets remains the IESO's Market Renewal initiative. If successful, Market Renewal will represent a fundamental redesign of Ontario's electricity market, which should address a number of known and enduring deficiencies with the existing design. The IESO is currently engaging stakeholders in preliminary design discussions, with final design decisions for the single schedule market and the incremental capacity auction expected in the first half of 2018. The Panel is supportive of the Market Renewal initiative and participates in the stakeholder efforts through its participation on the IESO's Market Renewal Working Group.

Chapter 1 also provides an update on the implementation of the expansion of the Industrial Conservation Initiative (ICI) to include certain consumers with peak demand between 500 kW and 1 MW, the suspension of renewable energy procurements, and an update on the IESO's stakeholder engagement dealing with system flexibility. Each one of these initiatives has

potential short-term or long-term implications for participants in the IESO-administered markets and Ontario ratepayers.

With respect to the Panel's recommendations in its previous semi-annual monitoring report, the IESO agreed with most of the recommendations and has identified steps that it intends to take in relation to them. However, the Panel believes that in some instances the IESO's response does not fully address the Panel's concerns. First, although the Panel recommended that that the IESO stop disbursing funds from the Transmission Rights Clearing Account until revisions are made to the disbursement methodology, the IESO has proceeded with a $76 million disbursement in June 2017. Of the $11.3 million that was paid to exporters, the Panel believes $9 million ought to have been for the benefit of Ontario ratepayers. In addition, while the IESO has stated that it is committed to improving the efficiency of the demand response auction, the IESO has not responded directly to the Panel's concern that there appears to be no need to procure any demand response capacity at this time given current and projected supply conditions. Upwards of $73 million has been paid to demand response resources through the 2016 and 2017 auctions.

Chapter 2: Market Outcomes

Chapter 2 presents data from the Summer 2016 Period including pricing, demand, supply, imports and exports. The data is accompanied by written commentary that puts the data in context.

Notable observations include the steady increase in overall system costs leading to increases in the prices paid by all classes of consumers, with the Global Adjustment continuing to be a significant component of total system costs.

Chapter 3: Analysis of Anomalous Market Outcomes

As part of its monitoring mandate the Panel regularly reviews market outcomes for results that fall outside expected norms. In recent monitoring reports the Panel has expanded its analysis of anomalous events beyond those which meet or exceed its historic price and uplift thresholds. The Panel now also reports on market outcomes it considers to be anomalous relative to the Market Objective and the Market Rules, outcomes it considers to be novel or infrequent, as well as outcomes that are relevant to current IESO initiatives and stakeholder engagements. As part of

its analysis of anomalous outcomes for the Summer 2016 Period, the Panel has identified a market design deficiency related to the operation of dispatchable loads.

This deficiency relates to the opportunity for dispatchable loads to earn unwarranted Congestion Management Settlement Credit (CMSC) payments as a result of conditions at their facilities. As a general rule, all dispatchable facilities (loads and generators) are required to follow the IESO's dispatch instructions. However, dispatchable facilities may request alternate dispatch instructions when following the IESO's initial instructions would endanger the safety of any person, damage equipment or violate any applicable law (referred to as SEAL-related constraints). While a SEAL-related constraint is a valid basis for requesting alternate dispatch instructions, the Panel views any CMSC payment attributable to such a circumstance as unwarranted. The existing Market Rules reflect this view by providing the IESO with the authority to recover SEAL-related CMSC payments from generators; however, these rules do not apply to dispatchable loads. The Panel is recommending that the IESO amend the Market Rules to enable the recovery of CMSC payments made to a dispatchable load where the payments are the result of operational constraints arising from conditions at the dispatchable load's facility. The Panel is also recommending that the IESO examine whether the scope of the current CMSC recovery provisions in the Market Rules in relation to generators should be expanded to cover CMSC payments made as a result of facility-specific operational constraints beyond SEAL-related constraints.

Recommendation 3-1:

The Independent Electricity System Operator should implement rules that allow it to recover Congestion Management Settlement Credit payments made to dispatchable loads when those payments are the result of an operational constraint arising from conditions at the dispatchable load's facility. The IESO should also examine whether the scope of the current provisions that allow it to recover CMSC payments from generators in relation to SEAL-related constraints should be expanded to cover any other operational constraints arising from conditions at the generator's facility.

Chapter 4: Matters to Report in the Ontario Electricity Marketplace

In Chapter 4 the Panel analyses potential market design deficiencies or concerns related to market participant conduct or activities of the IESO. Unlike Chapter 3, however, the issues

discussed in in Chapter 4 are not necessarily linked to events that occurred during the Summer 2016 Period.

The Panel has identified concerns related to the payment of constrained-on CMSC to exporters, as well as to the IESO's administration of the claw back mechanism that targets market participants that fail to respond to operating reserve activations.

Constrained-on CMSC for Exporters

The Panel has long expressed concerns that intertie traders can bid strategically to exploit the artificially low prices in the Northwest zone of the province. In particular, the enduring presence of negative prices creates an opportunity for exporters to obtain significant amounts of constrained-on CMSC payments to export power from Ontario. In January 2010 the Panel recommended that the IESO implement a floor price of $0/MWh for the purposes of calculating CMSC when market participants bid at negative prices. While exporters could receive power for free (prior to transaction costs), they would not be paid to export power from Ontario.

The IESO agreed with the Panel's assessment that a replacement bid price was warranted, but opted to implement a replacement price of -$125/MWh; meaning that exporters may be paid up to $125/MWh (prior to transaction costs) to take power from Ontario. The rationale for this choice was a desire to minimize the potential loss of efficient export transactions that may occur between jurisdictions with negative prices. The Panel's analysis reveals, however, that the loss of any potentially efficient export transactions associated with a replacement bid price of $0/MWh would be insignificant. The Panel has concluded that over an almost five-year period since the implementation of the -$125/MWh replacement bid price, Ontario consumers paid approximately $2.1 million more in uplift charges than would have been the case if the IESO had adopted a $0/MWh replacement price, with little or no corresponding efficiency benefit.

Recommendation 4-1:

The Independent Electricity System Operator should set the replacement bid price to $0/MWh, or slightly negative, when it calculates constrained-on Congestion Management Settlement Credit payments for exports bid at negative prices.

Failure to Provide Operating Reserves when Activated

The IESO, like other system operators in North America, is required to carry operating reserve (OR) to protect the power system against contingencies, such as the sudden loss of a large generating station. OR represents back-up power that is available when needed but is seldom called upon. In Ontario, the IESO usually carries about 1,500 MW of OR in any given hour. In exchange for committing to provide this back-up power, OR providers receive OR payments from the IESO.

If an OR provider fails to fully honour its commitment to the IESO, the Market Rules make provision for the IESO to implement a claw back of OR payments. The claw back is intended to ensure that the OR service provider will not receive payments for a service that it did not provide.

The Market Rules require the IESO Board of Directors to establish a materiality threshold below which no OR payments would be clawed back. Notionally, this threshold could be set from anywhere between 0 (i.e. all failures are subject to a claw back) to infinity (no failures are subject to a claw back). From market opening in May 2002 to June 2016, no threshold was established by the IESO and no claw backs were undertaken. In June 2016, the IESO Board of Directors set the threshold at infinity, effectively ensuring the claw back provision remains inoperative. The Panel believes an inoperative claw back provision is inappropriate. Moreover, the Panel's analysis reveals that had a 0 threshold been used, OR participants would have been subject to over $6 million in claw backs for OR services that they failed provide between January 2012 and October 2016. The Panel is therefore recommending that the materiality threshold value be revised such that OR payments are clawed back when a market participant fails to fully respond to its OR activation.

Recommendation 4-2A:

The Independent Electricity System Operator's Board of Directors should revise the materiality threshold value such that operating reserve payments are clawed back when a market participant fails to fully respond to its operating reserve activation.

The Panel has also identified what it believes to be a flaw in the formula for establishing the claw back amount. The existing formula assesses the degree to which a participant has failed to

honour its OR commitment as a function of that facility's total energy output. This inappropriately favours OR providers that, by happenstance, were producing energy at the time of the OR activation. The Panel believes that the claw back should instead be based on the ratio of energy not provided relative to the energy required by the activation, and is also recommending that this change be implemented.

Recommendation 4-2B:

When a market participant fails to fully respond to an operating reserve activation, the Independent Electricity System Operator should calculate the claw back based on the ratio of the energy not provided in response to the activation relative to the energy required by the activation.

Chapter 1: Market Developments and Status of Recent Panel Recommendations

This chapter contains an update on recent developments related to the IESO-administered markets, and provides commentary on the IESO's responses to recommendations contained in the Panel's previous semi-annual monitoring report.

1 *Developments related to the IESO-Administered Markets*

This section summarizes developments related to the IESO-administered markets that the Panel considers noteworthy.

Market Renewal

In March 2016 the IESO launched the Market Renewal initiative to address known challenges with the existing market design, and to create a foundation for a more dynamic energy market to meet future needs. In support of the Market Renewal initiative, the IESO launched the public Market Renewal stakeholder engagement, and appointed a Market Renewal Working Group consisting of 23 stakeholder representatives. The group includes generators, consumers, energy traders, emerging technology companies and a representative of the Panel.

In April 2017 the IESO published a commissioned study entitled *The Future of Ontario's Electricity Market: A Benefits Case Assessment of the Market Renewal Project.* The study estimated that Market Renewal would result in efficiency benefits to Ontario (net of implementation costs) totalling approximately $3.4 billion.[1] Electricity consumers will be the primary beneficiary of these efficiency gains, with estimated benefits of $180 million per year in 2021, increasing to $700 million per year in 2030.

Given the significant potential benefits associated with Market Renewal, the IESO has proceeded, with the assistance of the Working Group, to the high-level design phase of the project. The goal of the design phase is to consult with stakeholders in order to develop a high-level design for each of the five initiatives the IESO has identified as being part of Market Renewal:

- Single Schedule Market;
- Day-Ahead Market;

[1] See page vi of the report, available at: http://www.ieso.ca/en/sector-participants/market-renewal/overview-of-market-renewal

- Enhanced Real-Time Unit Commitment;
- More Frequent Intertie Scheduling; and
- Incremental Capacity Auction.

The IESO intends to use stakeholder engagements as the primary vehicle for developing the design elements for each initiative. To date, the IESO has launched stakeholder engagements related to the single schedule market and incremental capacity auction initiatives. These engagements have progressed past the fundamental education phase and into the preliminary design phase, to be followed by the final decisions phase (Q1 2018 for single schedule market and Q2 2018 for incremental capacity auction).[2]

Expansion of the Industrial Conservation Initiative

Effective July 2017, the Ontario Government again expanded the Industrial Conservation Initiative (ICI). When introduced in 2010, only customers with peak demand greater than 5 MW were eligible to participate; since then, the eligibility threshold has been reduced from time to time such that today all consumers with a peak demand of more than 1 MW can opt in, as can certain consumers with a peak demand of more than 500 kW. [3]

Each ICI customer's share of Global Adjustment charges is based on their consumption during the five coincident peak demand hours during a year. As ICI customers shift their consumption to minimize their Global Adjustment charges, those charges accrue to lower volume consumers.[4] However, the effect of that shift is currently mitigated as a result of the government's Fair Hydro Plan initiative.

Reduction in Renewable Energy Procurements

In September 2016 the Minister of Energy directed the IESO to suspend Ontario's Large Renewable Procurement II process for the procurement of over 1,000 MW of wind, solar,

[2] For more information on Market Renewal, including estimated timelines, consult the IESO's Market Renewal webpage, available at: http://ieso.ca/en/sector-participants/market-renewal/overview-of-market-renewal
[3] Resources with peak demand exceeding 500 kW but not more than 1 MW are eligible to participate in the ICI only if they are part of targeted manufacturing and industrial sectors; all resources over 1 MW may participate. For more information see the IESO's *Global Adjustment Class A Eligibility* webpage, available at: http://www.ieso.ca/en/sector-participants/settlements/global-adjustment-class-a-eligibility
[4] For more information on the Global Adjustment costs and their allocation amongst different groups of consumers, see Chapter 2.

hydroelectric and biomass generating capacity.[5] The decision to suspend the procurement process was informed by the IESO's *Ontario Planning Outlook* report, which concluded that Ontario has sufficient generating capacity to meet projected demand over the coming decade.

In December 2016 the Minister of Energy directed the IESO to suspend the remaining 150 MW of renewable generating capacity planned to be procured under the sixth round of the Feed-In Tariff program, given the proposed evolution of the microFIT program to net metering.[6]

Enabling System Flexibility

The IESO has identified the need to increase system flexibility in response to the forecast uncertainty associated with wind and solar generators. In June 2016 the IESO launched a stakeholder engagement to explore possible solutions.

The IESO's *2016 Operability Assessment* concluded that, in the short term, the system requires 1,000 MW of additional flexibility by 2018; that number has since been revised down to 740 MW in light of the suspension of Large Renewable Procurement II and reduced Feed-in Tariff targets.[7]

At its August 2017 stakeholder engagement meeting the IESO proposed a solution to the short-term flexibility need: increase the 30-minute Operating Reserve (OR) requirement when potential wind and solar forecast error exceeds the projected availability of flexible resources.[8] By increasing the OR requirement ahead of real-time, the IESO hopes to signal the upcoming need for additional flexibility while increasing the likelihood of committing additional non-quick start resources to provide that flexibility.

The IESO intends to address the longer term need for system flexibility through changes to be developed through its Market Renewal initiative.

[5] See the Minister of Energy's letter of direction to the IESO dated September 27, 2016, available at: http://www.ieso.ca/corporate-ieso/ministerial-directives
[6] See the Minister of Energy's letter of direction to the IESO dated December 16, 2016, available at: http://www.ieso.ca/corporate-ieso/ministerial-directives
[7] See slide 18 of the IESO's August 1, 2017 presentation to the *Enabling System Flexibility* stakeholder engagement, available at: http://www.ieso.ca/-/media/files/ieso/document-library/engage/esf/esf-20170801-presentation.pdf?la=en
[8] *Ibid*, slide 21-27.

2 *IESO Responses to Panel Recommendations in Last Monitoring Report*

Below are the recommendations made in the Panel's May 2017 Monitoring Report, and the IESO's responses to them.[9]

Recommendation	IESO Response
Recommendation 3-1 *The IESO should take steps to ensure that dispatchable loads are only compensated for the amount of operating reserve they were capable of providing in real-time. More fundamentally, the IESO should explore options for ensuring unavailable OR is not scheduled in the first instance.*	The IESO agrees that market participants should not be compensated for services that they are unable to provide. The Market Rules require all market participants, including dispatchable loads, to maintain accurate dispatch data and respond to IESO dispatch instructions for both energy and operating reserve. The IESO will assess what remedies are available to respond to the Panel's recommendation in 2017. These remedies could include but are not limited to changes to market design through Market Rules or investigations of non-compliance.
Recommendation 3-2 *The IESO should revise the methodology used to set the intertie failure charge to include the congestion rents that an intertie trader avoids when it fails a scheduled transaction for reasons within its control.*	The IESO agrees with the Panel's recommendation on intertie transaction failures; an intertie trader should not benefit by avoiding congestion rents when failing intertie transactions for reasons within its own control. Market Rules are in place that allow for the recovery of congestion rents that have been avoided, or Transmission Rights payments, when the intertie trader fails its transactions for illegitimate reasons. The IESO will consider the structure of intertie failure charges in 2017 and determine an appropriate avenue to address the issue identified by the Panel.

[9] See the May 30, 2017 letter from Bruce Campbell, then President and CEO of the IESO, to Rosemarie Leclair, Chair and CEO of the Ontario Energy Board, available at: https://www.oeb.ca/sites/default/files/IESO-Reply-to-OEB-MSP-Report-20170530.pdf

Recommendation 4-1 *a) The IESO should revise the manner in which it allocates disbursements from the Transmission Rights Clearing Account such that disbursements are proportionate to transmission service charges paid over the relevant accrual period.* *b) The IESO should not disburse any further funds from the Transmission Rights Clearing Account until such time that Recommendation 4-1(A) has been addressed.*	The current disbursement methodology of the Transmission Rights Clearing Account is to allocate disbursements to both internal and external loads based upon their share of demand. In 2017 the IESO will initiate a review of the disbursement allocation methodology to ensure it is both consistent with the intent and purpose of the Transmission Rights Clearing Account, and is aligned with current market and system needs. The outcome of the review, which will be completed and communicated to the Panel by the end of 2017, could also inform the Transmission Rights discussions that will take place as part of the IESO's Market Renewal Program. Given that the allocation method is Market-Rule based, the outcome of the review will also inform whether changes to the Market Rule are required. Meanwhile, until the review of the disbursement allocation methodology is completed, the IESO will continue with the semi-annual disbursements, as directed by the IESO Board and as detailed in Market Manual 5.5: Physical Markets Settlement Statements.
Recommendation 4-2 *The IESO should reassess the value provided by the capacity procured through its Demand Response auction in light of Ontario's surplus capacity conditions, as well as the stated preference of the government and the IESO (through its Market Renewal initiative) for technology-neutral procurement at least cost.*	The IESO was assigned responsibility for developing Demand Response (DR) in Ontario in 2013 with a mandate to develop DR to meet system and policy objectives in the short and longer term. Since that time, the IESO has developed a comprehensive work plan to ensure contracted resources are integrated cost effectively into the market. As a result of these initiatives, the annual cost of maintaining DR has dropped by almost 30%, while participation has increased significantly and new innovative approaches are continuing to emerge. In the short term, DR is contributing to the reliability of the Ontario grid as an integrated resource that is dispatched when it is economic relative to other resources. Over the longer term, the IESO agrees with the MSP that a technology-neutral capacity auction is a more cost effective way to procure capacity. The IESO has launched a stakeholder engagement to design such a mechanism as part of the Market Renewal Program. The learnings from the DR auction will help inform the design of a future incremental capacity auction and demonstrate how such a mechanism could work in Ontario. The IESO is also working together with stakeholders through the DR Working Group (DRWG). The IESO and the DRWG are committed to continuously improving the efficiency of the DR auction and working together to assess priorities for 2017. The DRWG work plan includes a number of projects to improve the efficiency of the DR auction, including a review of how DR is activated in the market.

3 *Panel Commentary on IESO Responses*

Recommendations 3-1 and 3-2

With respect to recommendations 3-1 and 3-2, the IESO agreed that action should be taken to address the inappropriate outcomes identified by the Panel, and committed to assessing potential solutions in 2017. In both cases, the Panel believes that the optimal solution would be one that prevents these inappropriate outcomes from arising in the first instance, rather than relying on after-the-fact payment recoveries or compliance actions.

Recommendation 4-1

The IESO committed to reviewing the current disbursement methodology for the Transmission Rights Clearing Account (TR Clearing Account) in 2017, to ensure that it is consistent with the intent and purpose of the TR Clearing Account, and aligned with current market and system needs.

With respect to the Panel's recommendation that the IESO stop disbursing funds from the TR Clearing Account until such time as revisions are made to the disbursement methodology, the IESO indicated that it would proceed with semi-annual disbursements as directed by the IESO Board of Directors and as detailed in the relevant Market Manual. The IESO has since made an additional disbursement of $76 million from the TR Clearing Account (in July 2017) using the existing methodology.[10] As a result, $11.3 million has been paid to exporters, $9 million of which ought in the Panel's view to have been for the benefit of Ontario ratepayers

Recommendation 4-2

The IESO was not directly responsive to the Panel's recommendation, as it has not indicated an intention to reassess the value provided by the capacity procured through its Demand Response (DR) auction. In the Panel's view, the IESO is procuring capacity through the DR auction at a time when additional capacity is not needed. Upwards of $73 million has been paid to demand response resources through the 2016 and 2017 auctions.

[10] See the IESO's June 1, 2017 News Release, available at: http://www.ieso.ca/en/sector-participants/ieso-news/2017/06/transmission-rights-clearing-account-disbursement.

While the IESO's response did not address the Panel's primary concern, it is consulting stakeholders about potential changes to the DR activation criteria. The changes being considered could increase the frequency with which DR resources are activated, and better align activations with system needs.[11]

[11] For more information, see the IESO's July 18, 2017 presentation entitled *Improved Utilization of DR*, available at: http://www.ieso.ca/en/sector-participants/engagement-initiatives/working-groups/demand-response-working-group

Chapter 2: Market Outcomes

This chapter reports on outcomes in the IESO-administered markets for the period between May 1, 2016 and October 31, 2016 (Summer 2016 Period), with comparisons to previous reporting periods as appropriate.

1 *Pricing*

This section summarizes pricing in the IESO-administered markets, including the Hourly Ontario Energy Price (HOEP), the effective price (including the Global Adjustment (GA) and uplift charges), operating reserve (OR) prices and transmission rights auction prices.

Table 2-1: Average Effective Electricity Price by Consumer Class
Summer 2015, Winter 2015/16 & Summer 2016 Periods
($/MWh)

Description:

Table 2-1 summarizes the average effective price in dollars per megawatt hour by consumer class for the Summer 2016 Period, the period from November 1, 2015 to April 30, 2016 (Winter 2015/16 Period) and the period from May 1, 2015 to October 31, 2015 (Summer 2015 Period). The effective price is the sum of the HOEP, the GA and uplift charges. Accordingly, it captures the hourly market price, payments under IESO reliability and other programs, prices payable for contracted and regulated generation and the costs of conservation and demand response programs. The effective price does not include all charges that appear on electricity bills, such as charges for transmission and distribution. Results are reported for three consumer groups: “Class A consumers”, “Class B consumers” and “All Consumers”.

Customer Class	Period	Average HOEP	Average Global Adjustment	Average Uplift	Effective Price
Class A	Summer 2016 Period	16.45	49.73	2.68	68.86
	Winter 2015/16 Period	8.32	57.44	1.72	67.48
	Summer 2015 Period	19.25	42.55	2.63	64.43
Class B	Summer 2016 Period	21.33	92.65	3.16	117.14
	Winter 2015/16 Period	10.31	102.14	1.91	114.37
	Summer 2015 Period	22.84	82.05	2.92	107.81
All Consumers	Summer 2016 Period				107.55
	Winter 2015/16 Period				105.05
	Summer 2015 Period				99.26

Relevance:

In Ontario, different consumer groups pay different effective prices. Consumers are divided into two groups: Class A, being consumers with an average monthly peak demand greater than 3 MW; and Class B, being all other consumers.[12]

The "All Consumers" group in Table 2-1 represents what the effective electricity price would have been for all consumers but for the change in the methodology for allocating the GA that took effect in January 2011. As of January 2011, the GA payable by Class A consumers is determined based on their peak demand factor, which is the ratio of their electricity consumption during the five peak hours in a year relative to total consumption by all consumers in each of those hours. The remaining and proportionately larger share of the GA, which includes the GA avoided by Class A consumers who reduced their consumption during the five peak hours of the year, is allocated on a monthly basis to Class B consumers based on their total consumption in that month.[13]

[12] The peak demand threshold for Class A consumers was 3 MW during the Summer 2016 Period; the threshold has since been lowered to 500 kW for certain consumers, and to 1 MW for all consumers (see section 1 of Chapter 1). For more information on the Global Adjustment allocation methodology, see Ontario Regulation 429/04 (Adjustments under Section 25.33 of the Act) made under the *Electricity Act, 1998*, available at: http://www.ontario.ca/laws/regulation/040429

[13] For more information on the GA allocation methodology and its effect on each consumer class, see pages 69-92 of the Panel's June 2013 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2012-Oct2012_20130621.pdf

In previous Panel reports, Class A consumers that are embedded within a distribution system (as opposed to being directly-connected to the IESO-controlled grid) were combined with Class B consumers for the purposes of the Panel's effective price calculations and analyses. Starting in this report, the Panel has moved embedded Class A consumers from the Class B consumer class to the Class A consumer class for the purposes of its reporting, including Table 2-1. This change allows for a clearer delineation between Class A and Class B consumers.

The Panel has also adopted a new assumption regarding the behaviour of embedded Class A consumers. Starting in this report the Panel assumes that embedded Class A consumers behave like directly-connected Class A consumers (and thus have the same load profile). Previously the Panel made no such assumptions about the behaviour of Class A consumers (hence the use of a "Class B & Embedded Class A" group in previous reports).

The Panel must make assumptions with respect to the behaviour of embedded Class A consumers due to data limitations. These data limitations preclude an assessment of exactly how effective embedded Class A consumers are at shifting or curtailing consumption to avoid GA costs, and the degree to which any net consumption reductions are being achieved through increased behind-the-meter generation. [14]

The Panel's April 2015 Monitoring Report explained the need to obtain generation and consumption data at an hourly level of granularity, specifically for embedded generation, behind-the-meter generation and embedded Class A consumption.[15] The Panel noted that assessing the impacts of certain market changes – such as the 2011 change to the methodology for allocating the GA – loses precision without access to this data. In addition, assessing the province's overall demand for electricity becomes increasingly difficult as a larger portion of that demand is no longer served by the province's high-voltage power system. The need for this data is even more pronounced today given recent changes in the Class A eligibility threshold and the increase in the number of embedded Class A consumers.

[14] Given the change in the Panel's definition of consumer groups (from "Direct Class A" to all "Class A" and "Class B & Embedded Class A" to just "Class B"), there is no direct comparison to be made between effective prices reported in this report and those from earlier reports. All references to effective price in this report – including all tables and figures – reflect the Panel's new methodology.
[15] For more information on data limitations see pages 105-109 of the Panel's April 2015 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2013-Apr2014_20150420.pdf

Commentary and Market Considerations:

The average effective price increased for both Class A and B consumers during the Summer 2016 Period relative to the previous two reporting periods. Compared with the Summer 2015 Period, the average effective price for Class A and Class B consumers increased by $4.43/MWh and $9.33/MWh respectively. The primary driver of the increase in effective prices was an increase in total system costs, as opposed to a significant decrease in the consumption volumes over which these costs are recovered.

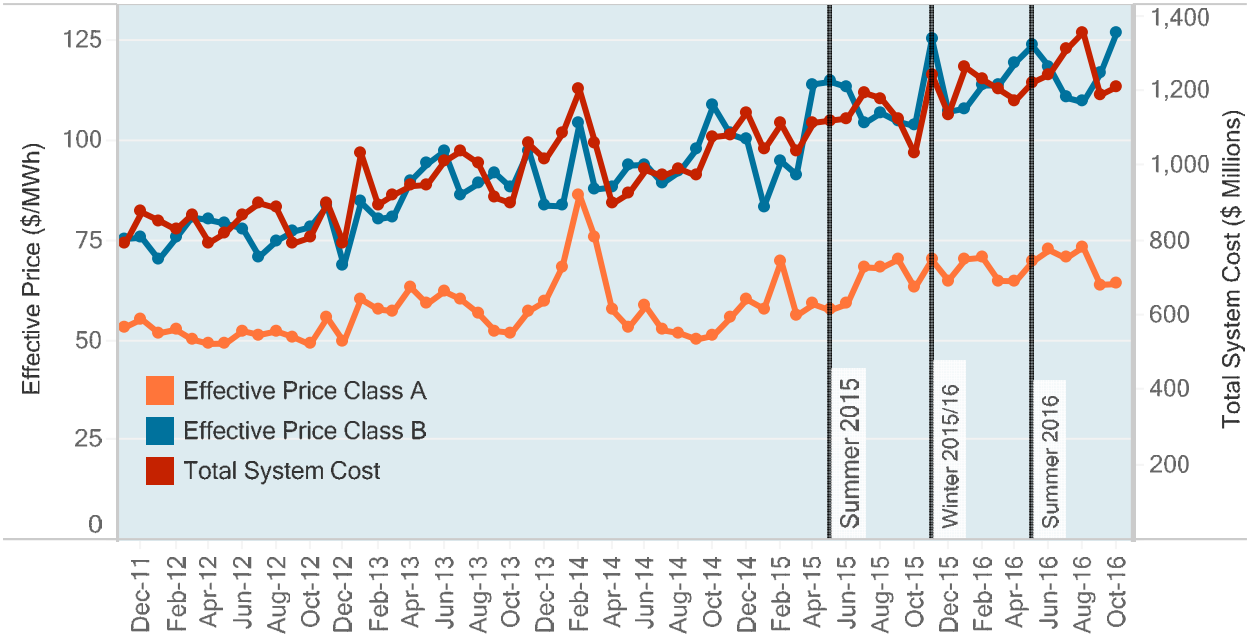
The HOEP and the GA have an inverse relationship because the GA is primarily composed of payments to contracted and regulated generating resources that are intended to make up for shortfalls between market revenues and the contracted or regulated rates of those resources.[16] Compared to the Winter 2015/16 Period, the HOEP rose during the Summer 2016 Period while the average GA fell for all consumer classes.

Figure 2-1: Monthly Average Effective Electricity Price and System Costs
November 2011 – October 2016
($/MWh & $)

Description:

Figure 2-1 plots the monthly average effective price for Class A and Class B consumers, as well as the monthly system cost for the previous five years.

[16] The costs associated with compensating loads under the IESO's demand response pilots and administering various other conservation programs (such as the saveONenergy program) are also recovered through the GA. Additional information regarding the GA is available at: http://www.ieso.ca/sector-participants/settlements/guide-to-wholesale-electricity-charges



Relevance:

This figure highlights the changes in the effective price paid by each consumer class over the past five years, as well as the steady increase in total system costs.

Commentary and Market Considerations:

In the Summer 2016 Period, there were both record high total system costs ($1.35 billion in August 2016) and a record high effective price for Class B consumers ($127.10/MWh in October 2016). The Class A effective price increased modestly from the Winter 2015/16 Period.

Class A consumers can avoid GA costs by minimizing their consumption during peak system hours. The GA that is avoided by Class A consumers is payable by Class B consumers. As a result, over the past 5 years Class A effective prices have not risen in step with system costs and Class B consumers continue to bear the majority of increased system costs.

Figures 2-2A & 2-2B: Average Effective Electricity Price by Consumer Class and by Component

Description:

Figures 2-2A and 2-2B separate the monthly average effective price into its three components (average HOEP, average GA and average uplift charges) for Class A and Class B consumers for the previous two years.

As previously explained, the GA and the HOEP have an inverse relationship: when the HOEP decreases, the GA increases, albeit not necessarily one-for-one. The GA allocation methodology and the extent to which Class A consumers respond to the incentives it provides are responsible for the significant difference in the average effective price paid by each consumer class. When the average GA makes up an increasing portion of system cost, the average effective price paid by Class B consumers increases proportionately more than the average effective price paid by Class A consumers. This relationship is readily apparent in the Summer 2016 Period, as it has been in past reporting periods.

Figure 2-2A: Average Effective Price for Class A Consumers by Component
November 2014 – October 2016
($/MWh)

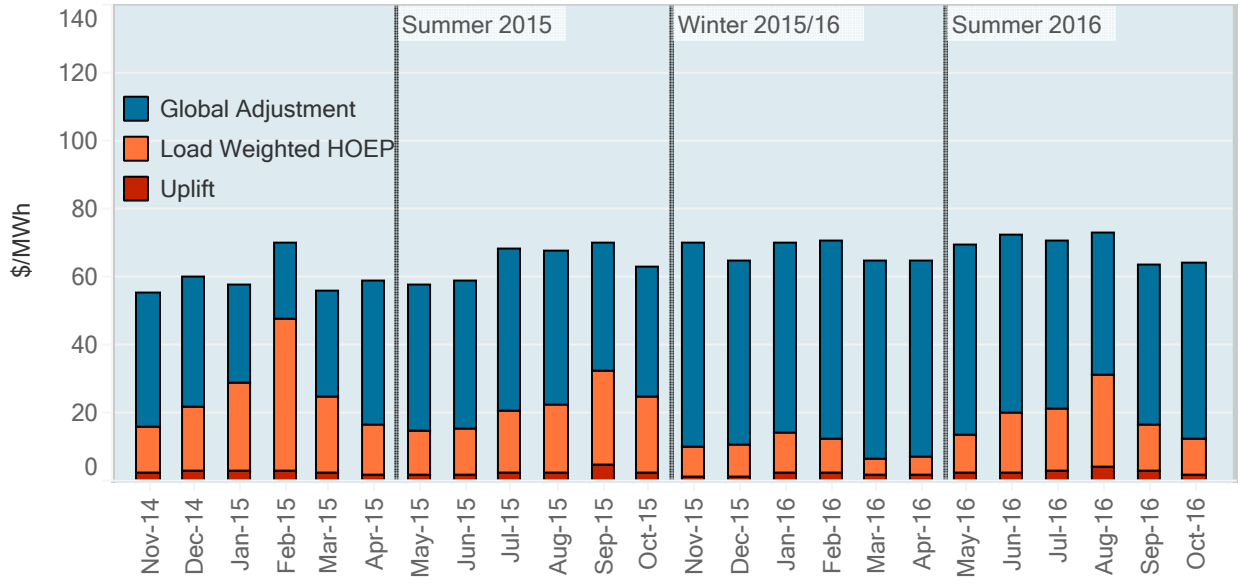
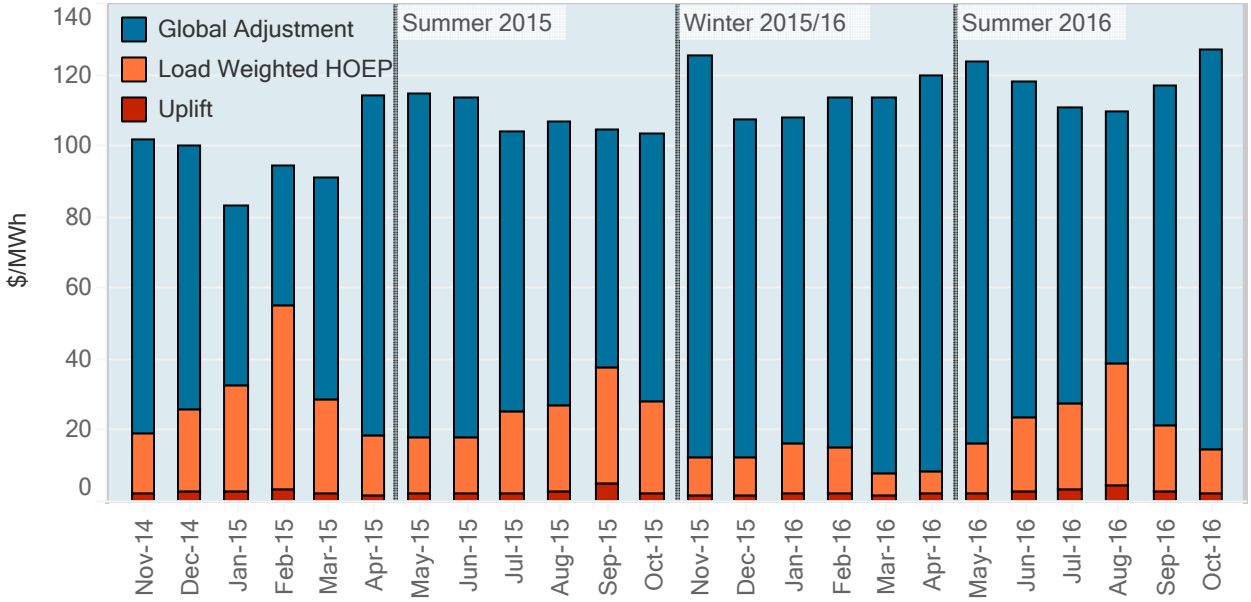


Figure 2-2B: Average Effective Price for Class B Consumers by Component
November 2014 – October 2016
($/MWh)



Relevance:

These two figures illustrate how changes in the individual components of the effective price affect the average effective price paid by each consumer class.

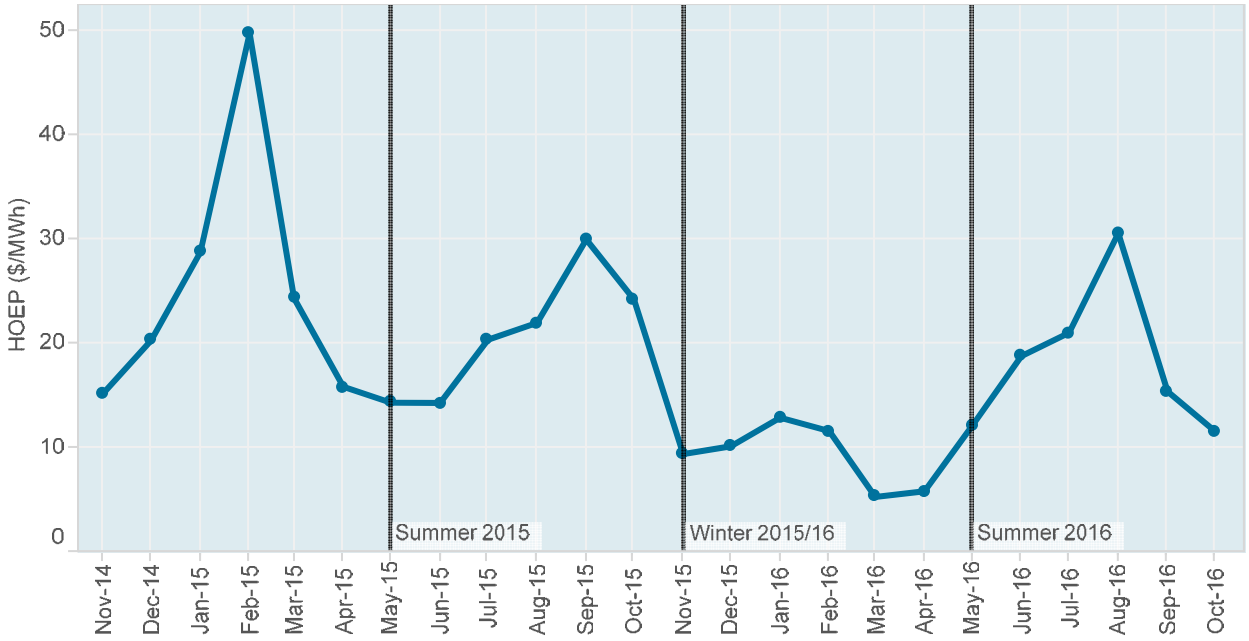
Commentary and Market Considerations:

The average effective price for Class B consumers continues to be significantly higher than that of Class A consumers, a trend that began with the change in the GA allocation methodology introduced in 2011.

Figure 2-3: Monthly (Simple) Average HOEP
November 2014 – October 2016
($/MWh)

Description:

Figure 2-3 displays the simple monthly average HOEP for the previous two years.



Relevance:

The HOEP is the market price for a given hour and is one component of the effective price paid by consumers. The HOEP is the simple average of the twelve market clearing prices (MCPs) set every five minutes within an hour. The HOEP is paid directly by consumers who participate in the wholesale electricity market, and indirectly by consumers who pay Regulated Price Plan prices set by the Ontario Energy Board.

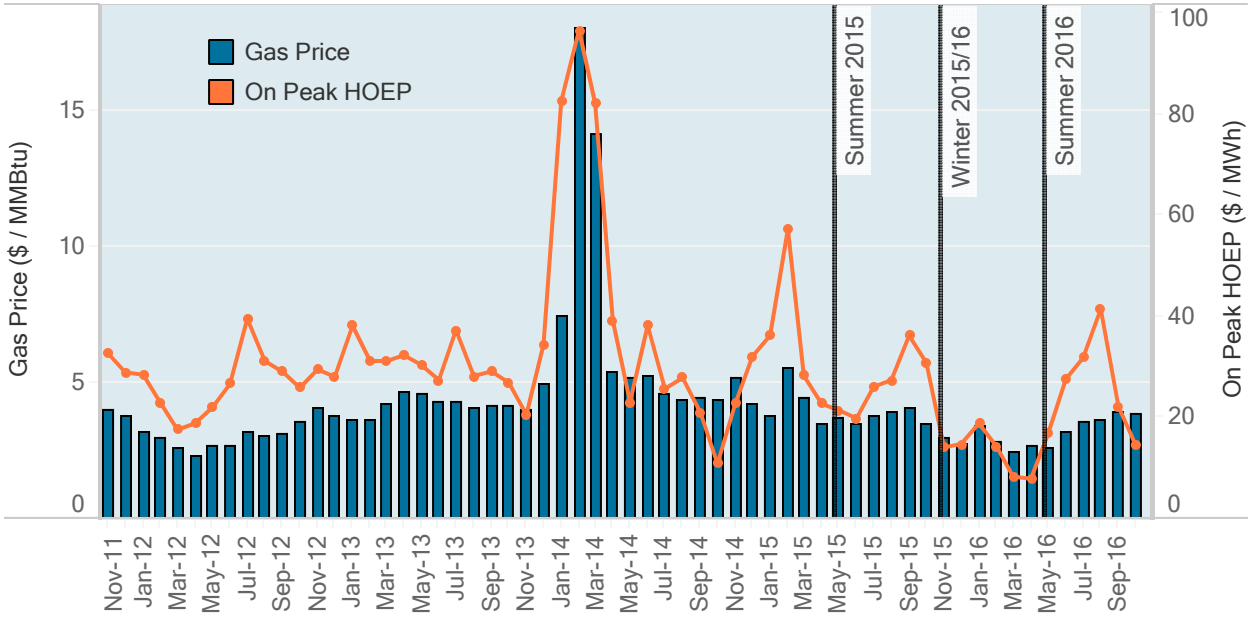
Commentary and Market Considerations:

Demand in the Summer 2016 Period was nearly 2 TWh higher than in the Summer 2015 Period. Despite higher demand, the average HOEP was lower by over $2/MWh. The lower average HOEP is partially attributed to 829 MW of low marginal cost wind and solar capacity that was added to the grid following the Summer 2015 Period.

Figure 2-4: Natural Gas Price and On-peak HOEP
November 2011 – October 2016
($/MWh & $/MMBtu)

Description:

Figure 2-4 plots the monthly average Dawn Hub day-ahead natural gas price and the average monthly HOEP during on-peak hours[17] for the previous five years.



Relevance:

The Dawn Hub is the most active natural gas trading hub in Ontario, and has the largest gas storage facility in the province. Gas-fired facilities can typically purchase gas day-ahead in order to ensure sufficient time to arrange for transportation; for that reason, the Dawn Hub day-ahead gas price is a relevant measure of the cost of natural gas in Ontario. Natural gas prices are compared to the HOEP during on-peak hours, as gas-fired facilities frequently set the price during these hours.

[17] On-peak hours are defined as 7:00 AM to 11:00 PM, Monday to Friday (excluding holidays). Off-peak hours are all other hours.

Commentary and Market Considerations:

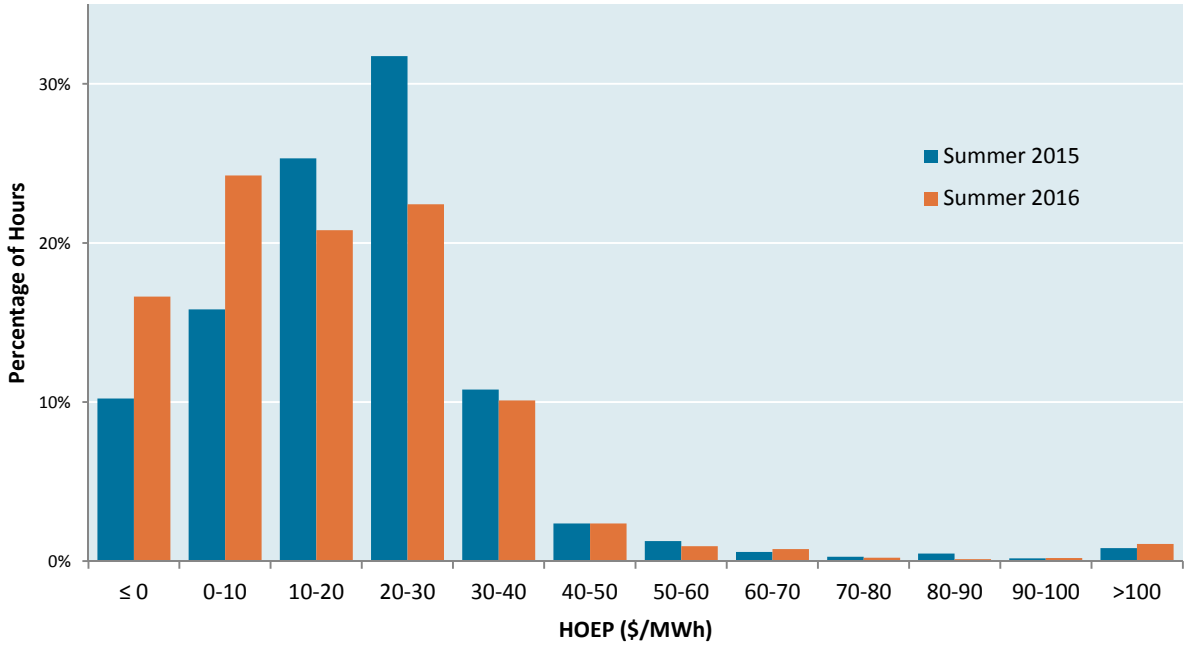
Dawn Hub gas prices, which had been in decline since the Winter 2013/14 Period, rose modestly in the Summer 2016 Period (average day-ahead gas price of $3.42/MMBtu, compared to $2.84/MMBtu in the Winter 2015/16 Period).

In the past, changes in natural gas prices have been positively correlated with movements in the on-peak HOEP. The correlation in the Summer 2016 Period was very weak, which can be attributed to a significant increase in wind and hydro replacing gas facilities as the marginal resource (see Figure 2-6).

Figure 2-5: Frequency Distribution of the HOEP
Summer 2015 & Summer 2016 Periods
(% of hours & $/MWh)

Description:

Figure 2-5 compares the frequency distribution of the HOEP as a percentage of total hours for the Summer 2016 and Summer 2015 Periods. The HOEP is grouped in increments of $10/MWh, except for all negative-price hours which are grouped together with all $0/MWh values.



Relevance:

The frequency distribution of the HOEP illustrates the proportion of hours that the HOEP falls into a given price range, and provides information regarding the frequency of high and low prices.

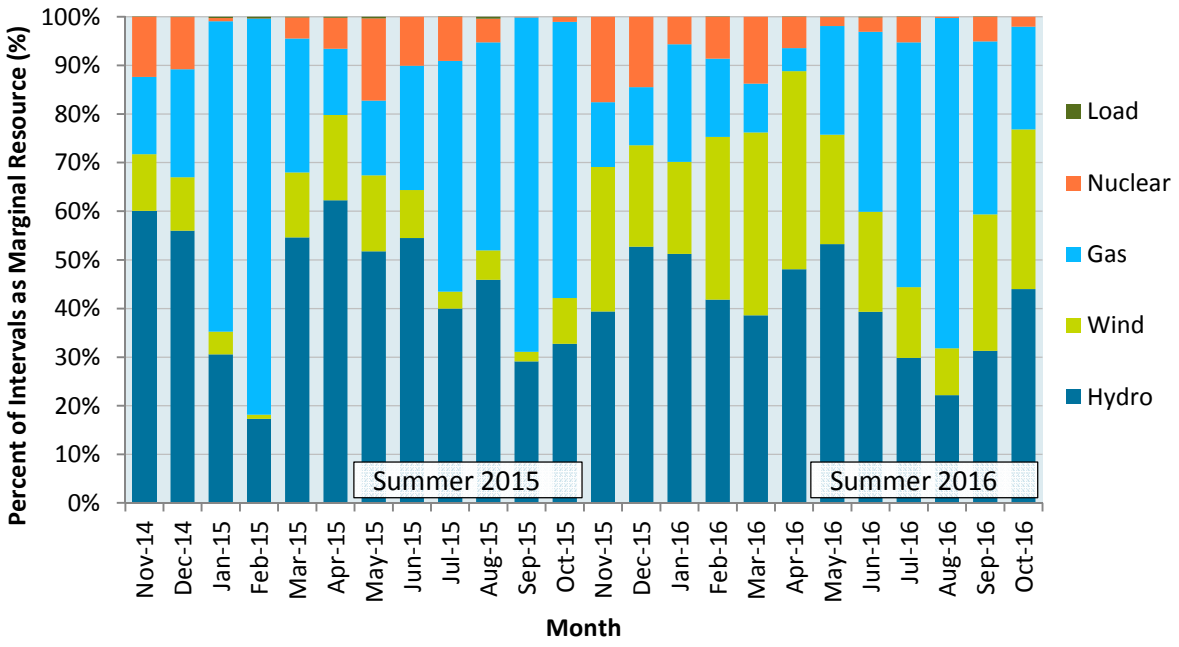
Commentary and Market Considerations:

The frequency distribution of the HOEP shows an increase in the amount of non-positive price hours (zero and negative) in the Summer 2016 Period relative to the Summer 2015 Period. Overall, the HOEP was lower than in the Summer 2015 Period, despite higher demand. The addition of 829 MW of renewable energy capacity to the grid after the end of the Summer 2015 Period contributed to the increased frequency of lower prices.

Figure 2-6: Share of Resource Type setting the Real-Time MCP
November 2014 - October 2016
(% of intervals)

Description:

Figure 2-6 presents the monthly share of intervals in which each resource type set the real-time MCP, for the previous two years.



Relevance:

The relative frequency of each resource type setting the real-time MCP is useful in understanding trends in the real-time MCP.

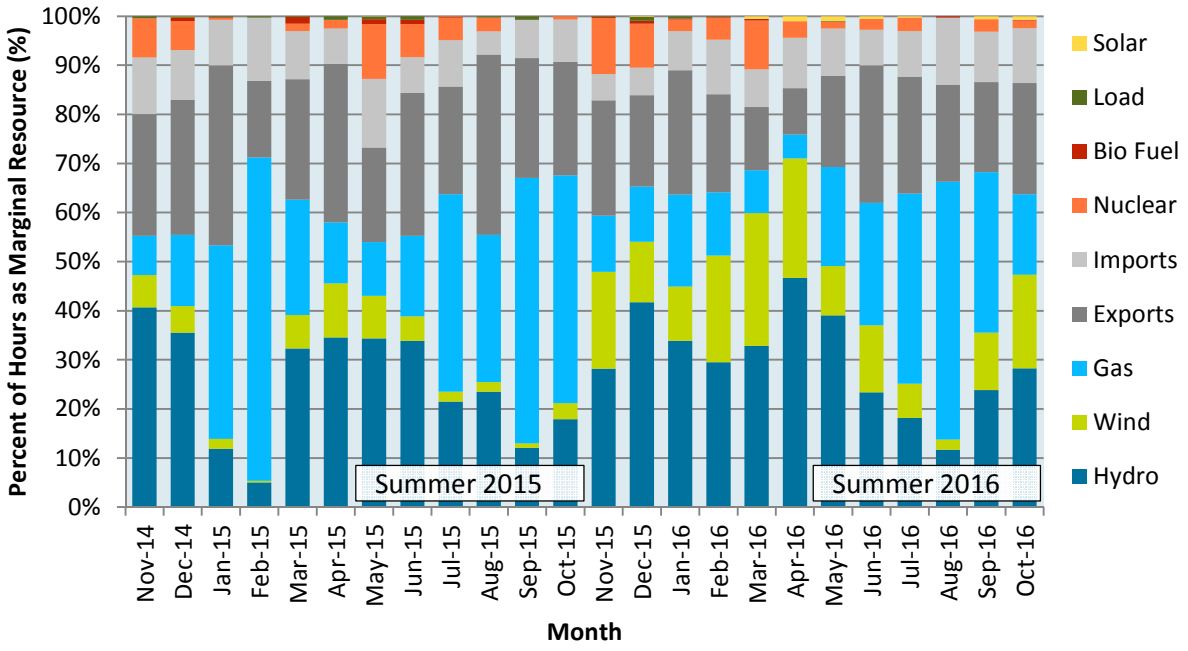
Commentary and Market Considerations:

Wind set the MCP in 21% of all intervals in the Summer 2016 Period, which is more frequent than in any previous summer period. As installed wind capacity continues to increase in Ontario, the Panel expects wind to continue to set the MCP with increasing frequency, especially during periods of low demand. There was a decrease in the share of gas generators setting the MCP compared to the Summer 2015 Period (from 42% to 38% of all intervals).

Figure 2-7: Share of Resource Type setting the One-Hour Ahead Pre-Dispatch MCP
November 2014 – October 2016
(% of hours)

Description:

Figure 2-7 presents the monthly share of hours in which each resource type set the hour-ahead pre-dispatch (PD-1) MCP, for the previous two years.



Relevance:

When compared with Figure 2-6 (resources setting the real-time MCP), the relative frequency of each resource type setting the PD-1 MCP provides insight into how the marginal resource mix changes from pre-dispatch to real-time. Of particular importance is the frequency with which imports and exports set the PD-1 MCP, as these transactions are unable to set the real-time MCP.[18] When the price is set by an import or export in pre-dispatch, a divergence between the pre-dispatch and the real-time MCP is more likely to occur.

Commentary and Market Considerations:

Wind set the PD-1 MCP in 11% of all hours in the Summer 2016 Period, compared to 4% of all hours during the Summer 2015 Period. As noted above, installed wind capacity continues to increase in Ontario as contracted resources are still coming online. Therefore, the Panel expects wind to continue to set the MCP with increasing frequency, especially during periods of low demand. Gas-fired resources set the PD-1 MCP 31% of all hours in the Summer 2016 Period, down from 33% of the time during the Summer 2015 Period.

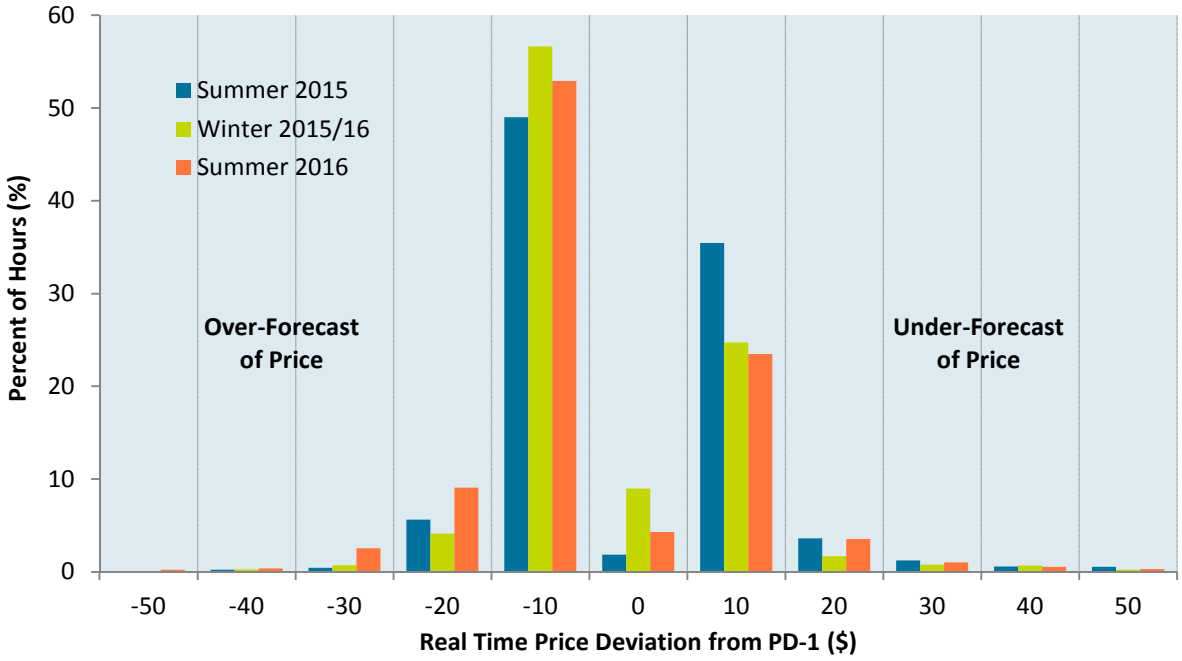
Figure 2-8: Difference between the HOEP and the PD-1 MCP
Summer 2015, Winter 2015/16 & Summer 2016 Periods
(% of hours, $)

Description:

Figure 2-8 presents the frequency distribution of differences between the HOEP and the PD-1 MCP for the Summer 2016, Winter 2015/16 and Summer 2015 Periods. The price differences are grouped in $10/MWh increments, save for the $0/MWh category which represents no change between the PD-1 MCP and the HOEP. The number of instances where the absolute difference between the PD-1 MCP and the HOEP exceeded $50/MWh is negligible in the context of this graph, and so is not included in Figure 2-8. The same is true of Figure 2-9 in relation to the absolute difference between the three-hour ahead MCP and the HOEP.

Positive differences on the horizontal axis represent a price increase from pre-dispatch to real-time, while negative differences represent a price decrease.

[18] Due to scheduling protocols, imports and exports are scheduled an hour ahead of real-time. In real-time, import and export quantities are fixed for a given hour and their prices are adjusted to -$2,000 and $2,000/MWh, respectively. This means that they are scheduled to flow for the entire hour regardless of the price, though their schedule may change within an hour to maintain reliability. As a result, they are treated like non-dispatchable resources in real-time and cannot set the MCP.



Relevance:

The PD-1 MCP determines the schedules for import and export transactions for real-time delivery. While intertie transactions are scheduled on the basis of the PD-1 MCP, they are settled on the basis of the HOEP. To the degree that supply and demand conditions change from PD-1 to real-time, imports or exports may be over- or under-scheduled relative to the HOEP. For instance, an exporter that is willing to pay the PD-1 MCP may not want to pay the HOEP if it is higher, but would be required to do so. Conversely, if prices fall, the exporter could see a higher profit but the volume of exports could be sub-optimal.

Commentary and Market Considerations:

PD-1 prices in the Summer 2016 Period were a less accurate predictor of real-time prices than in the previous two reporting periods. In the Summer 2016 Period, the pre-dispatch sequence was within +/- $10/MWh of the HOEP 81% of the time compared, to 86% in the Summer 2015 Period and 90% in the Winter 2015/16 Period. The average absolute price difference was $8.39/MWh, up from $6.58/MWh in the Summer 2015 Period and $5.20/MWh in the Winter 2015/16 Period. As in periods past, the PD-1 MCP was far more likely to be over-forecast than under-forecast.

Table 2-2: Factors Contributing to Differences between PD-1 MCP and HOEP Summer 2015, Winter 2015/16 & Summer 2016 Periods (MWh)

Description:

Real-time prices diverge from PD-1 prices as a result of changing conditions from pre-dispatch to real-time. The Panel has identified the following as the six main factors that contribute to the difference between the PD-1 MCP and the HOEP:

Supply

- Self-scheduling and intermittent generation forecast deviation (other than wind);
- Wind generation forecast deviation;
- Generator outages; and
- Import failures/curtailments.

Demand

- Pre-dispatch to real-time demand forecast deviation; and
- Export failures/curtailments.

Imports or exports setting the PD-1 MCP can result in price divergences as these transactions cannot set the price in real-time. Table 2-2 displays the average absolute difference between PD-1 and real-time for all of the above-noted factors, save for the effect of generator outages. Generator outages tend to be infrequent, although short-notice outages can have significant price effects. Ontario demand is also included to provide a relative sense of the size of the deviations.

Factor	Average Hourly Absolute Difference (MWh)		
	Summer 2015 Period	Winter 2015/16 Period	Summer 2016 Period
Ontario Demand	15,205	15,435	15,602
Demand Forecast Deviation	211	219	209
Self-Scheduling and Intermittent Forecast Deviation (Excluding Wind)	20	17	21
Wind Forecast Deviation	124	140	185
Net Export Failures/Curtailments	82	90	78

Relevance:

Identifying the factors that lead to deviations between the PD-1 MCP and the HOEP provides insight into the root causes of price risks that participants, particularly importers and exporters, face as they enter offers and bids into the market.

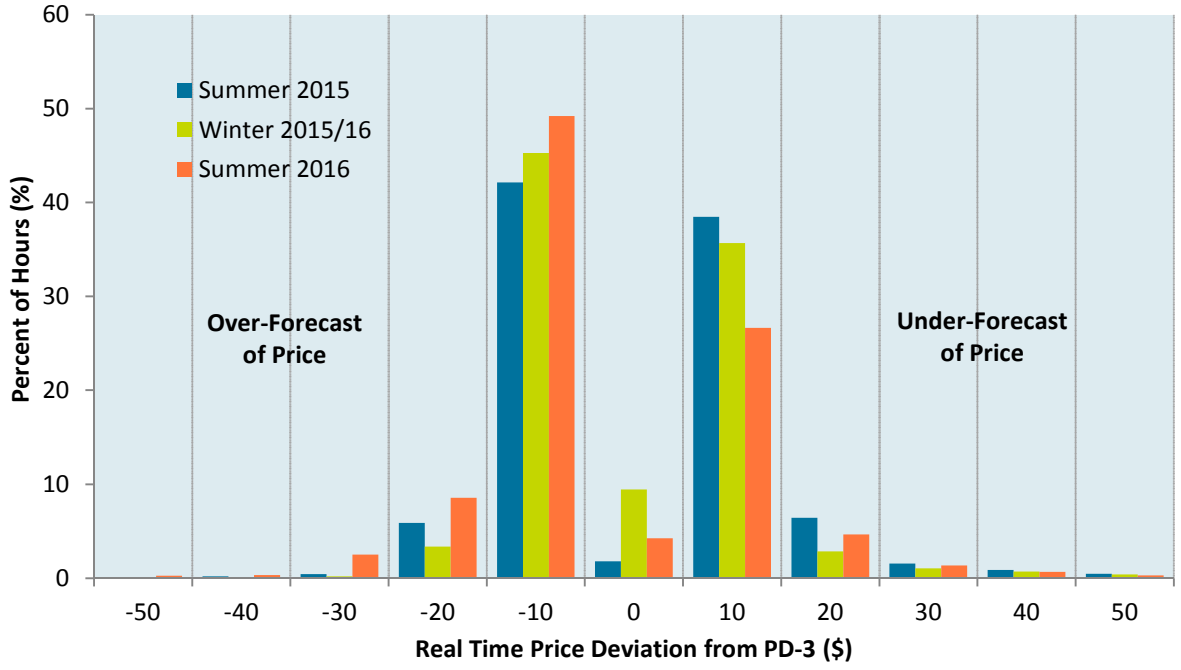
Commentary & Market Considerations:

Wind forecast deviation increased significantly over the last three reporting periods, primarily due to the increase in installed wind capacity. All other factors have varied as well, although to a significantly lesser degree.

Figure 2-9: Difference between the HOEP and the PD-3 MCP
Summer 2015, Winter 2015/16 & Summer 2016 Periods
(% of hours, $)

Description:

Figure 2-9 presents the frequency distribution of differences between the HOEP and the three-hour ahead pre-dispatch (PD-3) MCP during the Summer 2016, Winter 2015/16 and Summer 2015 Periods. The price differences are grouped in $10/MWh increments, save for the $0/MWh category which represents no change between the PD-3 MCP and the HOEP. Positive differences on the horizontal axis represent a price increase from PD-3 to real-time, while negative differences represent a price decrease.



Relevance:

The PD-3 MCP is the last price signal seen by the market prior to the closing of the offer and bid window, after which offers and bids may only be changed under limited circumstances with the approval of the IESO.

Differences between the HOEP and the PD-3 MCP indicate changes in the supply and demand conditions from PD-3 to real-time. The resultant changes in price are informative for non–quick start facilities and energy limited resources,[19] both of which rely on pre-dispatch prices to make operational decisions. Price changes are also important to intertie traders, whose bids and offers are often informed by pre-dispatch prices in Ontario.

Commentary and Market Considerations:

In the Summer 2016 Period the PD-3 MCP was within +/- $10/MWh of the HOEP 80% of the time, compared to 82% for the Summer 2015 Period and 90% in the Winter 2015/16 Period.

When comparing PD-3 to PD-1 (Figure 2-8), the forecast accuracy was similar during the Summer 2016 Period, and the PD-3 MCP was similarly far more likely to be over-forecast than under-forecast.

Figure 2-10: Monthly Global Adjustment by Component
November 2014 – October 2016
($)

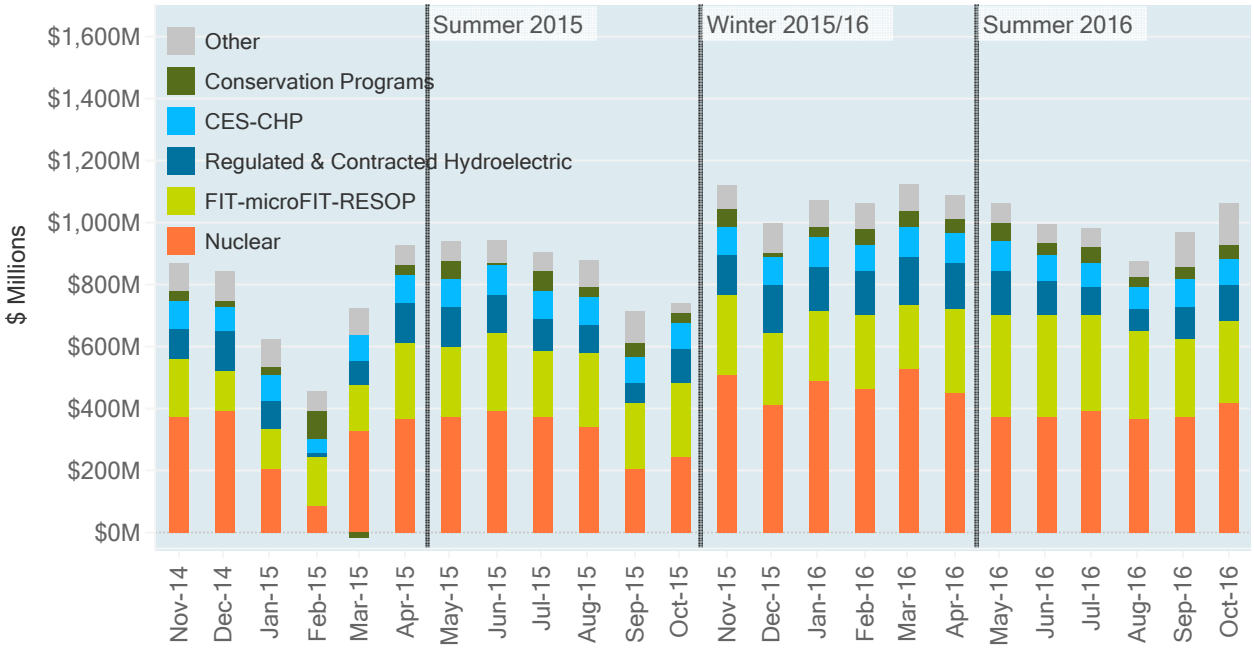
Description:

Figure 2-10 plots the payments to various resources and recovered through the GA each month, by component, for the previous two years. For this purpose, the total GA is divided into the six following components:

- Payments to nuclear facilities (Bruce Nuclear Generating Station and Ontario Power Generation's (OPG) nuclear assets);
- Payments to holders of Clean Energy Supply contracts and Combined Heat and Power (CES-CHP) contracts;

[19] Energy limited resources constitute a subset of generation facilities that experience fuel restrictions that prevent them from operating at full capacity at all times. Energy limited resources differ from intermittent resources (such as wind) in that they have the ability to store fuel, thus allowing them to optimize production over their storage horizons. For example, a hydroelectric facility with limited water availability and a storage pond may store water during relatively lower priced hours, and use it to generate and sell electricity during relatively higher priced hours.

- Payments to regulated or contracted hydroelectric generation;
- Payments to holders of contracts for renewable power (Feed-in Tariff (FIT), microFIT and the Renewable Energy Standard Offer Program (RESOP));
- Payments related to the IESO's conservation programs; and
- Payments to others (including under the IESO's demand response pilots, to holders of non-utility generator contracts and under the contract with OPG's Lennox Generating Station).



Relevance:

Showing the GA by component identifies the extent to which each component contributes to the total GA. The high GA totals for a particular component may be the result of increases in contracted rates, increased production, increased capacity, or decreases in the HOEP.

Commentary and Market Considerations:

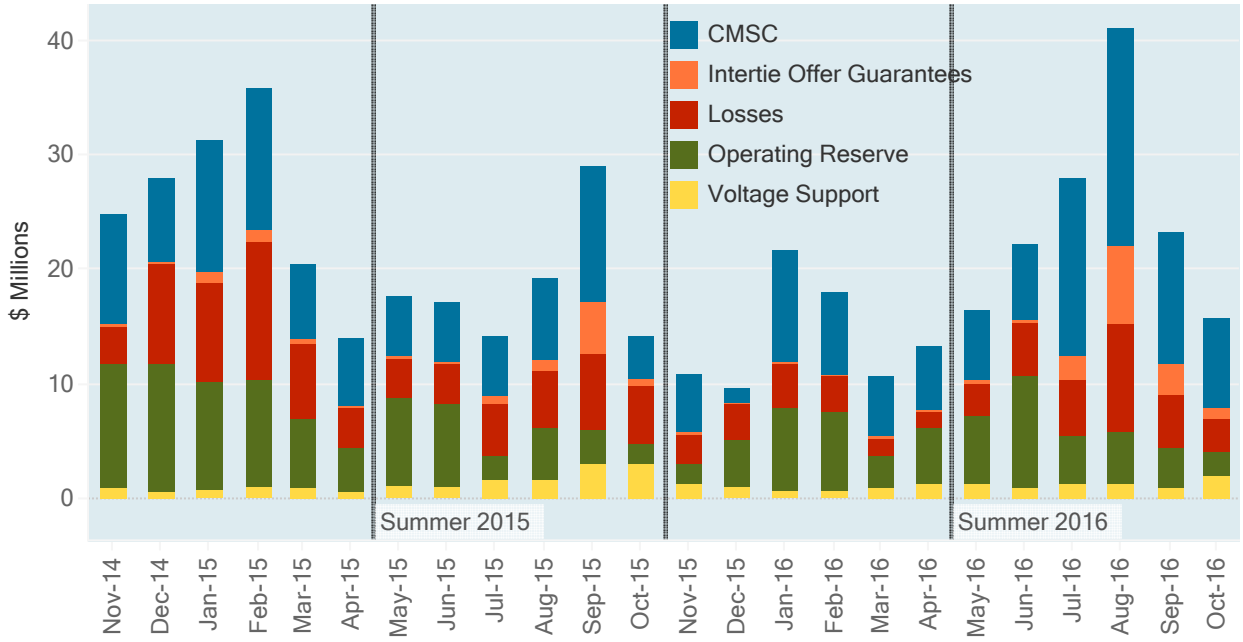
Two GA components, payments to "FIT-microFIT-RESOP" generators and payments in the "Other" category, increased in the Summer 2016 Period, while payments in the remaining four fell. FIT-microFIT-RESOP payments surpassed $300 million/month for the first time in May 2016. It is expected that these payments will continue to increase as renewable capacity in Ontario continues to come online. Payments in the "Other" category also reached a new high of

$133 million/month in October 2016, largely as a result of higher payments to non-utility generators.

Figure 2-11: Total Hourly Uplift Charge by Component and Month
November 2014 – October 2016
($)

Description:

Figure 2-11 presents the total hourly uplift charges (Hourly Uplift) by component and month, for the previous two years. Hourly Uplift components include Congestion Management Settlement Credit (CMSC) payments, Intertie Offer Guarantee (IOG) payments, OR payments, voltage support payments and transmission losses.



Relevance:

Hourly Uplift is a component of the effective price in Ontario. It is charged to wholesale consumers (including distributors) – based on their share of total hourly demand – in order to recover the costs associated with various market programs and design features.

Commentary and Market Considerations:

In August 2016, total Hourly Uplift exceeded $40 million for the first time since March 2014, primarily driven by an increase in CMSC payments ($18.9 million), losses ($9.6 million) and IOG payments ($6.8 million). Hourly Uplift tends to follow trends in the HOEP, as higher prices

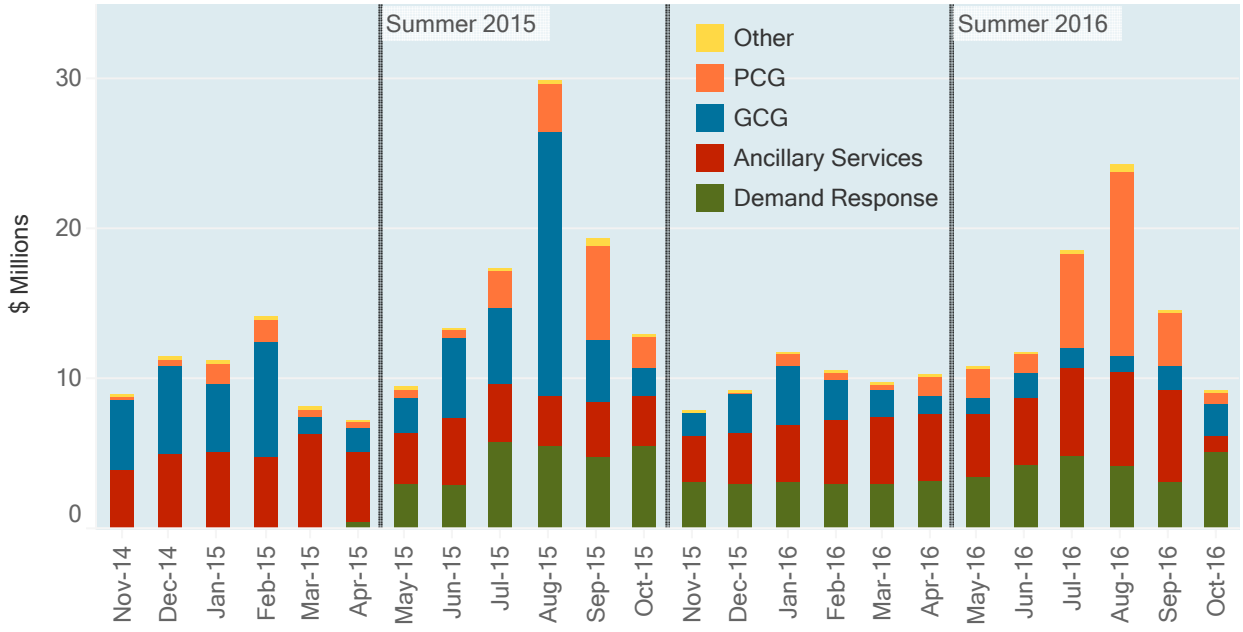
mean more costly losses and congestion and higher guarantees to importers. As shown in Figure 2-3, August 2016 had the highest average HOEP of the Summer 2016 Period, and the second highest average monthly HOEP of the two year period covered by the figure.

Figure 2-12: Total Monthly Uplift Charge by Component
November 2014 – October 2016
($)

Description:

Figure 2-12 plots the total monthly uplift charges (Monthly Uplift) by component, for the previous two years. Monthly Uplift has the following components:[20]

- Payments for ancillary services (i.e. regulation service, black start capability, monthly voltage support);
- Guarantee payments to generators under the Day-Ahead Production Cost Guarantee (PCG) and Real-Time Generation Cost Guarantee (GCG) programs;
- Payments for the IESO's demand response capacity, such as capacity procured through the demand response auction; and
- Other, which includes charges and rebates such as compensation for administrative pricing and the local market power rebate, among others.



[20] The figure includes all uplifts charged, except those charged on an hourly basis.

Relevance:

Monthly Uplift is a component of the effective price in Ontario. It is charged to wholesale consumers (including distributors) based on their share of total daily or monthly demand, as applicable, in order to recover the costs associated with various market programs and design features.

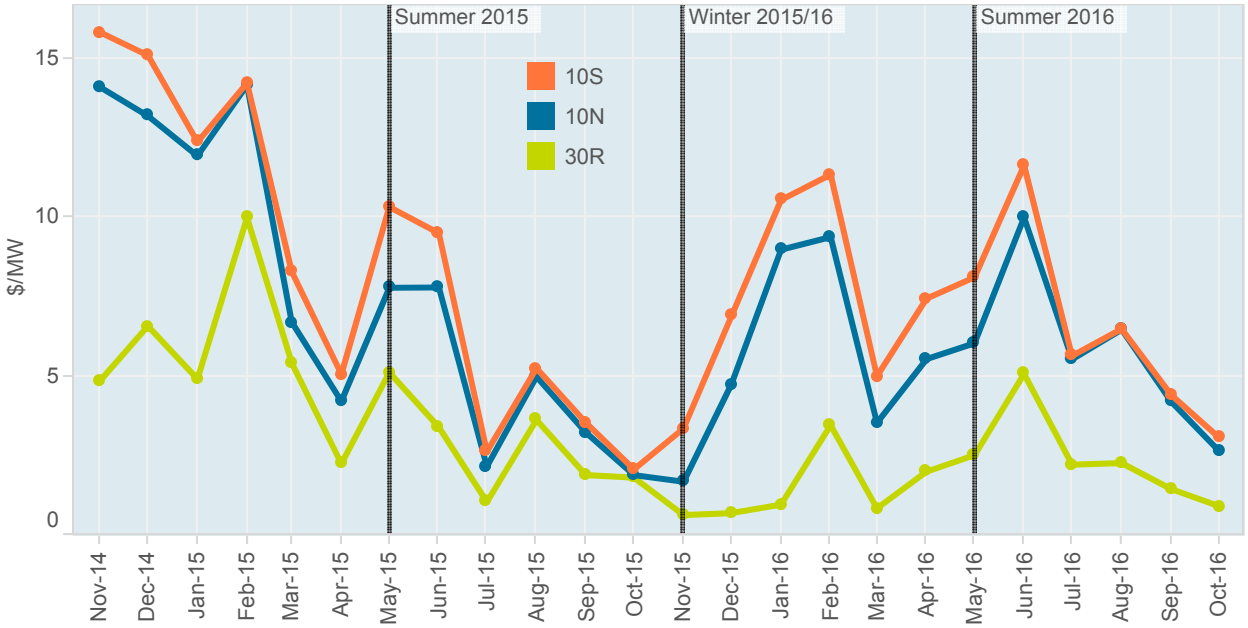
Commentary and Market Considerations:

PCG and GCG payments make up a substantial portion of Monthly Uplift and tend to trend with market demand (Figure 2-20); higher demand typically necessitates the commitment of more non-quick start facilities. Total Monthly Uplift in the Summer 2016 Period was down slightly from the Summer 2015 Period, with the majority of commitment costs shifting from the GCG program to the PCG program (i.e. from real-time to day-ahead).

Figure 2-13: Average Monthly Operating Reserve Prices by Category
November 2014 – October 2016
($/MW)

Description:

Figure 2-13 plots the monthly average OR price for the previous two years for the three OR markets: 10-minute spinning (10S), 10-minute non-spinning (10N) and 30 minute (30R).



Relevance:

The three OR markets are co-optimized with the energy market, meaning that resources are scheduled to minimize the combined costs of energy and OR. As such, prices in these markets tend to be subject to similar dynamics.

Resources offer supply into the OR markets just as they offer supply into the energy market; however, OR demand is set unilaterally by the IESO's total OR requirement. The reliability standards set by the North American Electric Reliability Corporation and the Northeast Power Coordinating Council stipulate that the IESO must schedule sufficient OR to allow the grid to recover from the single largest contingency (such as the largest generator tripping offline) within 10 minutes, plus additional OR to recover from half of the second largest contingency within 30 minutes. These requirements ensure that the IESO-controlled grid can operate reliably.

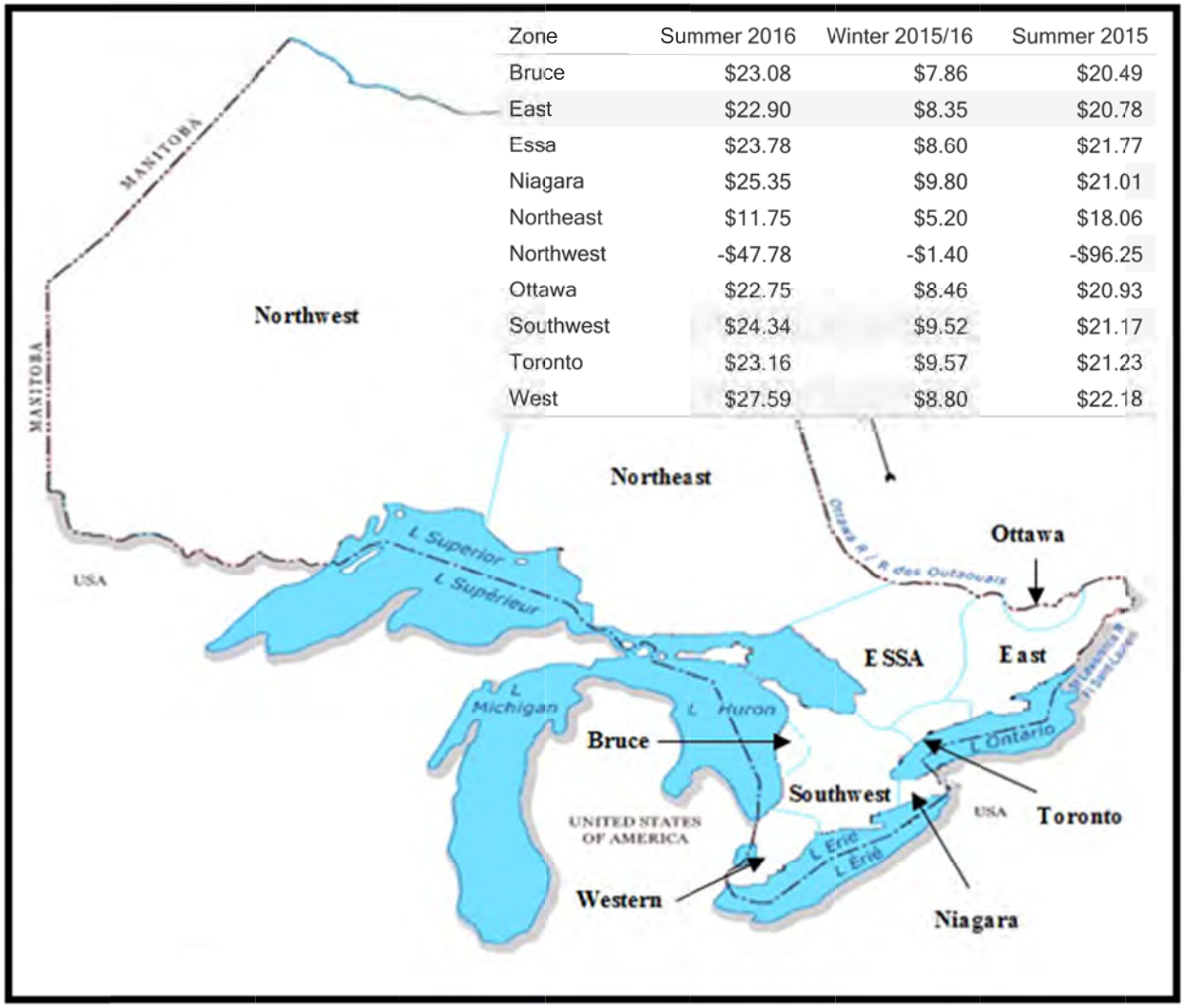
Commentary and Market Considerations:

OR prices in all three markets were moderately higher in the Summer 2016 Period relative to the Summer 2015 Period. The high OR prices in June 2016 reflect a single high price event occurring within a two-hour period. In that case, demand was under-forecast and wind resources were over-forecast, leaving an energy shortfall that could only be met with faster ramping, more expensive resources. Since energy and operating reserve are co-optimized, this energy shortfall translated into high OR prices.

Figure 2-14: Average Internal Nodal Prices by Zone
Summer 2015, Winter 2015/16 & Summer 2016 Periods
($/MWh)

Description:

Figure 2-14 illustrates the average nodal price of Ontario's ten internal zones for the Summer 2016, Winter 2015/16 and Summer 2015 Periods. In principle, nodal prices represent the cost of supplying the next megawatt-hour of energy at a given location.



Zone	Summer 2016	Winter 2015/16	Summer 2015
Bruce	$23.08	$7.86	$20.49
East	$22.90	$8.35	$20.78
Essa	$23.78	$8.60	$21.77
Niagara	$25.35	$9.80	$21.01
Northeast	$11.75	$5.20	$18.06
Northwest	-$47.78	-$1.40	-$96.25
Ottawa	$22.75	$8.46	$20.93
Southwest	$24.34	$9.52	$21.17
Toronto	$23.16	$9.57	$21.23
West	$27.59	$8.80	$22.18

Relevance:

While the HOEP is the uniform wholesale market price across Ontario, the cost of satisfying demand for electricity may differ across the province due to limits on the transmission system and the cost of generation in different regions. Nodal prices approximate the marginal cost[21] of electricity in each region and reflect Ontario's internal transmission constraints. Differences in average nodal prices identify zones that are separated by system constraints. In zones in which average nodal prices are high, supply is more expensive or the supply conditions are relatively tight; in zones in which average nodal prices are low, supply is cheaper or the supply conditions are relatively more abundant.

[21] There are instances where nodal prices do not reflect the marginal cost of electricity, such as those discussed in section 1.1 of Chapter 4.

In general, nodal prices outside the northern parts of the province move together. Most of the time the nodal prices in the Northwest and Northeast zones are significantly lower than the nodal prices in the rest of the province due primarily to two factors: first, in these zones, there is surplus low-cost generation (in excess of demand); and second, there is insufficient transmission to transfer this low-cost surplus power to the southern parts of the province.

Contributing to negative prices in the northern zones are hydroelectric facilities operating under must-run conditions. Must-run conditions necessitate that units generate at certain levels of output for safety, environmental, or regulatory reasons. Under such conditions, market participants offer the must-run energy at negative prices in order to ensure that the units are economically selected and scheduled.

Commentary and Market Considerations:

Given the relatively static location of generators, loads and transmission lines over time, changes in nodal prices are largely driven by demand. With the exception of the Northeast, nodal prices within all zones were higher during the Summer 2016 Period relative to the Summer 2015 Period. These higher prices can be largely attributed to hotter summer conditions causing increased demand during the period.

Figures 2-15 & 2-16: Congestion by Interface Group

Description:

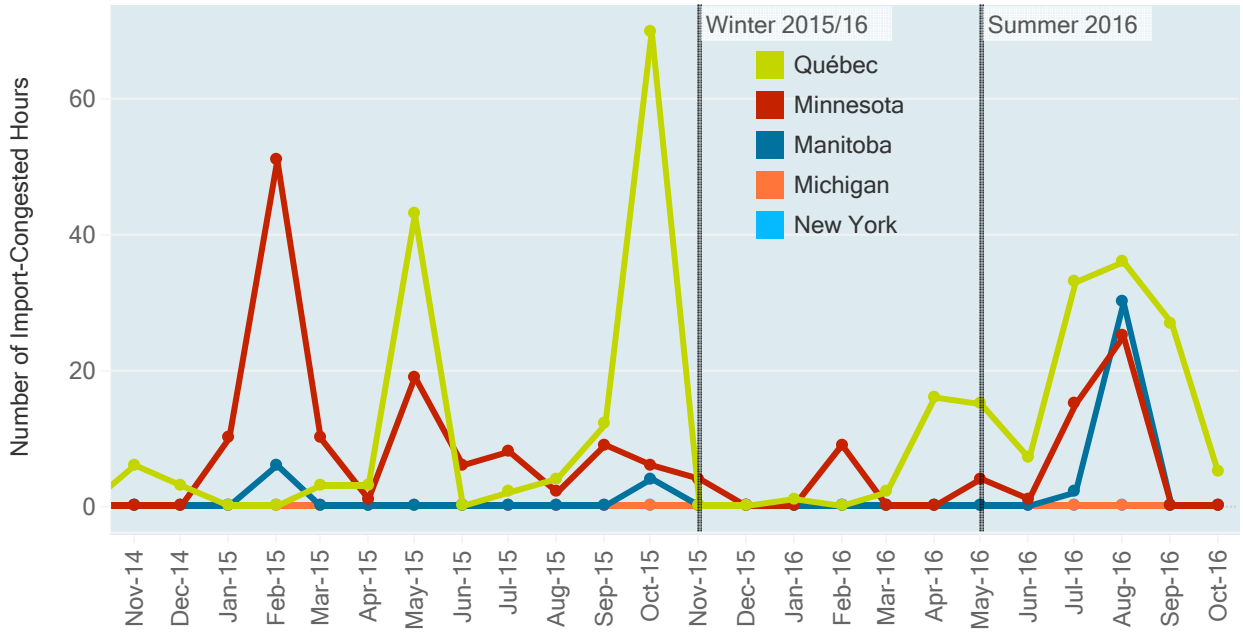
Figures 2-15 and 2-16 report the number of hours per month of import and export congestion, respectively, by interface for the previous two years.

Relevance:

The interties that connect Ontario to neighbouring jurisdictions have finite transfer capabilities. The supply of intertie transfer capability is dictated by the available capacity at each interface, and also by line outages and de-ratings. When an intertie has a greater amount of economic net import offers (or economic net export bids) than its PD-1 transfer capability, the intertie will be import (or export) congested. Demand for intertie transfer capability is driven in part by price differences between Ontario and other jurisdictions.

The price for import and export transactions can differ from the MCP, as it is based on the intertie zonal price where the transaction is taking place. For a given intertie, importers are paid the intertie zonal price, while exporters pay the intertie zonal price. When there is import congestion, importers receive less for the energy they supply while exporters pay less for the energy they purchase—the intertie zonal price is lower than the MCP. When there is export congestion, importers receive more for the energy they supply while exporters pay more for the energy they purchase—the intertie zonal price is greater than the MCP. The difference between the intertie zonal price and the MCP is called the Intertie Congestion Price (ICP). The ICP for a given hour is calculated in PD-1 depending on whether or not the PD-1 energy schedule has more economic transactions than the intertie transmission lines can accommodate. The ICP is positive when there is export congestion and negative when there is import congestion. This is discussed in more detail in the "Relevance" section associated with Figure 2-17.

Figure 2-15: Import Congestion by Interface Group
November 2014 – October 2016
(number of hours in the unconstrained schedule)

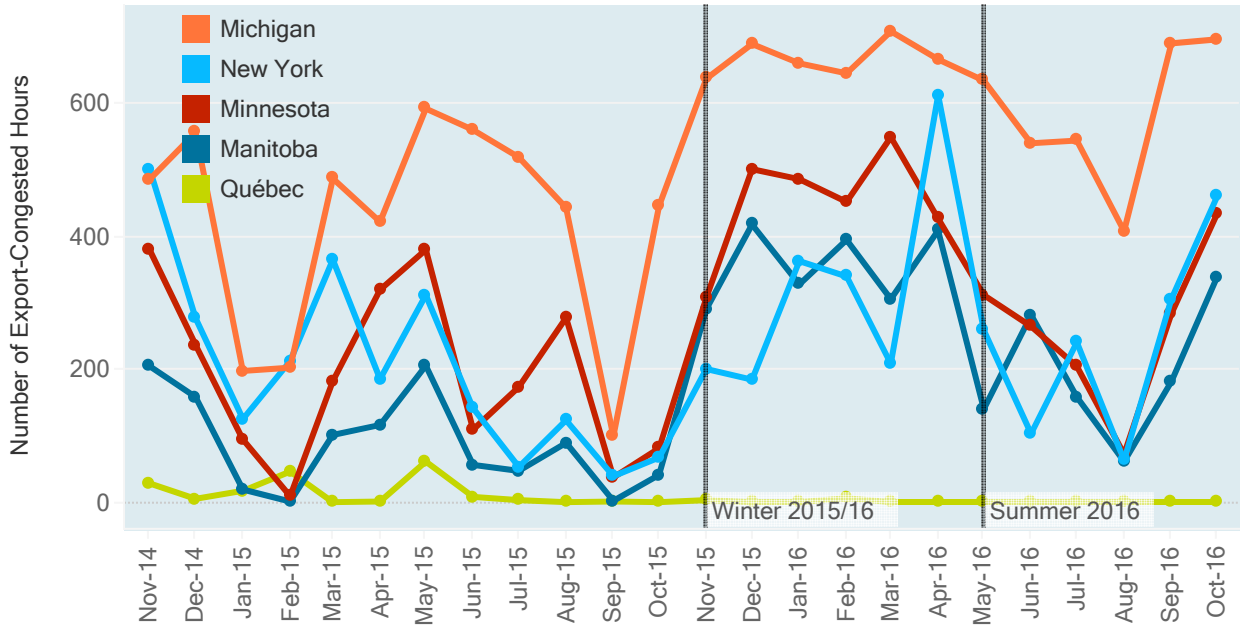


Commentary and Market Consideration:

Import congestion rose between June and August 2016 before declining in September and October. These variations were observed at the Manitoba, Minnesota and Québec interties. The higher HOEP in Ontario during August was a major cause of the increase in import congestion.

As prices in Ontario came down during September and October, there were fewer profitable import opportunities available and consequently import congestion decreased.

Figure 2-16: Export Congestion by Interface Group
November 2014 – October 2016
(number of hours in the unconstrained schedule)



Commentary and Market Consideration:

Export congestion generally trended downwards between May and August 2016 before coming back up in September and October. At the Michigan intertie there were approximately 690 hours of export congestion in September and October; this is close to a two year high. The low HOEP in Ontario combined created greater potential for profitable export opportunities in these months.

Table 2-3: Monthly Average Hourly Electricity Spot Prices – Ontario and Surrounding Jurisdictions
May 2016 – October 2016
($/MWh)

Description:

Table 2-3 lists the average hourly real-time spot prices for electricity, by month, in Ontario and the surrounding external jurisdictions with which electricity intertie traders operating in Ontario commonly trade. The Ontario price reported reflects only the HOEP and does not include the GA

or uplift.[22] Absent congestion at an interface, importers receive, and exporters pay, the HOEP when transacting in Ontario.

The external prices reported are the real-time locational-marginal prices that correspond with the node on the other side of Ontario's interface with each jurisdiction. Québec is a frequent trading partner, but does not operate a wholesale market and thus is not included.

Month	Ontario (HOEP)	Manitoba*	Michigan (MISO)*	Minnesota (MISO)*	New York (NYISO)*	Pennsylvania New Jersey Maryland Operator (PJM)*
May	12.01	18.66	26.65	20.51	18.87	28.36
Jun	18.69	25.69	33.20	27.35	22.97	32.36
Jul	20.92	30.10	40.27	32.00	28.30	36.95
Aug	30.45	32.06	47.44	34.17	31.91	39.33
Sep	15.29	25.15	39.74	27.48	23.64	33.05
Oct	11.46	26.46	38.29	28.72	23.72	31.12

* All prices listed for each jurisdiction reflect the marginal price of energy. Costs associated with capacity, such as Ontario's GA or NYISO, PJM, or MISO's capacity markets, are not considered in inter-jurisdictional trade.

Relevance:

One objective of energy trading is to exploit arbitrage opportunities. Intertie traders attempt to purchase (export) low-priced power from one jurisdiction and sell (import) that power to another jurisdiction at a higher price to capture the price differential.

Price differences between jurisdictions can change from one hour to the next due to changes in any of the numerous factors which determine demand (e.g. weather) and supply (e.g. outages). Changes in the price differential will impact the direction of energy trade between those jurisdictions. Energy trade may not always flow from jurisdictions with low prices to jurisdictions with high prices; imperfect information, timing issues and rapidly changing conditions can lead to energy trade that at a given time appeared profitable or efficient but becomes unprofitable or inefficient later. However, average prices over longer time horizons are informative on expected trends in the direction of energy trade between jurisdictions.

As discussed in the Relevance section associated with Figures 2-15 and 2-16, importers and exporters in Ontario do not receive or pay the HOEP if congestion exists at an interface in a

[22] Exporters pay most uplifts charges, but do not pay the GA.

given hour. Congestion can erode or even reverse the original arbitrage opportunity between the HOEP and the external jurisdiction's price. However, the HOEP and the spot price in the external jurisdiction remain two key pieces of information in determining whether to import to or export from Ontario.

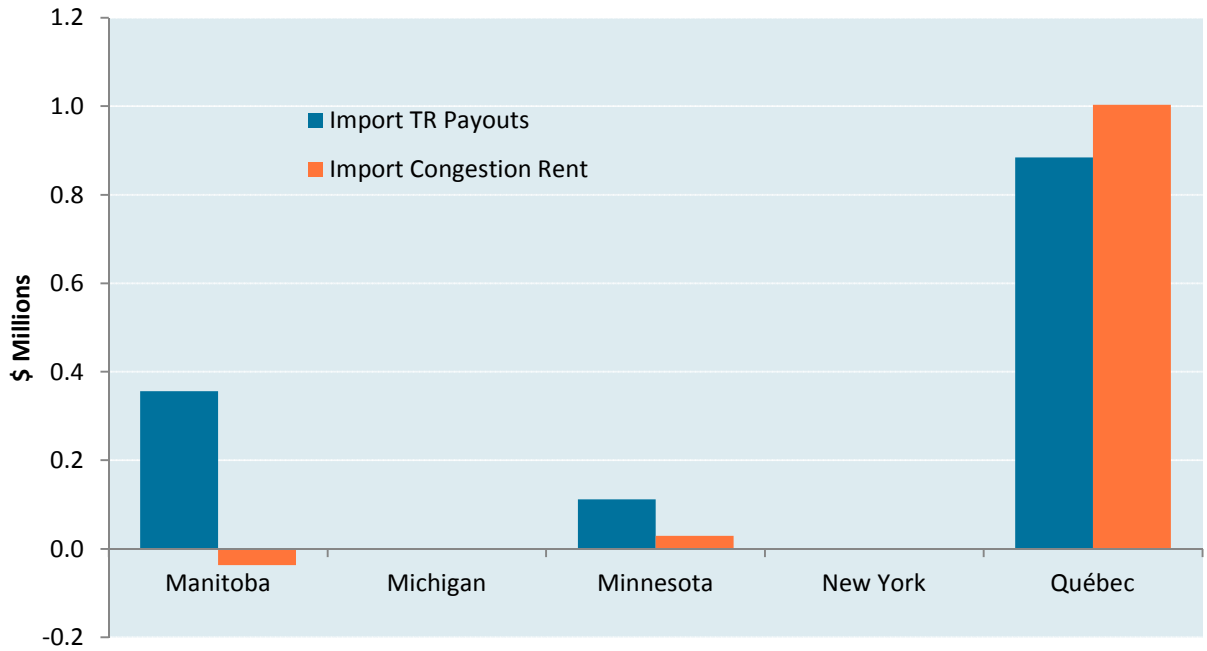
Commentary and Market Considerations:

During the Summer 2016 Period, the HOEP was significantly lower than the energy price in all of the surrounding jurisdictions. As expected, Ontario was a net exporter over the period (see Figure 2-24), often with congested interties in the export direction (see Figure 2-16).

Figure 2-17: Import Congestion Rent & Transmission Rights Payouts by Interface Group
May 2016 – October 2016
($)

Description:

Figure 2-17 compares the total import congestion rent collected to total transmission rights (TR) payouts by interface group for the Summer 2016 Period.



Relevance:

As discussed in the Relevance section associated with Figures 2-15 and 2-16, an intertie zonal price is less than the Ontario price when an intertie is import congested; the difference in prices

is the ICP and is equal to the difference (if any) between the PD-1 MCP and the PD-1 intertie zonal price. While the importer is paid the lesser intertie zonal price, the buyer in the wholesale market still pays the HOEP. The difference between the amount collected from the purchaser and the amount paid to the importer is known as import "congestion rent". Congestion rent accrues to the IESO's Transmission Rights Clearing Account (TR Clearing Account). This account is discussed in greater detail in the Relevance section associated with Figure 2-19.

To enable intertie traders to hedge against the risk of price fluctuations due to congestion, the IESO administers TR auctions. TRs are sold by intertie and direction (import or export) for periods of one month or one year. The owner of a TR is entitled to a payment (or "payout") equal to the ICP multiplied by the amount of TRs they hold every time congestion occurs on the intertie in the direction for which they own a TR. TRs therefore allow an intertie trader to hedge against congestion-related price fluctuations by ensuring that intertie traders are settled on the HOEP and not the intertie zonal price. An intertie trader that holds the exact same amount of import TRs as the amount of energy they are importing is perfectly hedged against congestion, as TR payouts will exactly offset price differences between the HOEP and the price in the intertie zone. Payouts to TR holders are disbursed from the TR Clearing Account.

While TR payouts should theoretically be offset by congestion rent collected, in practice this is often not the case. One of the main reasons for this is the difference between the number of TRs held by market participants and the number of net imports/exports flowing during hours of congestion. When TR payouts exceed congestion rent collected, the TR Clearing Account is drawn down; the opposite is true when congestion rent collected exceeds TR payouts.

In addition to congestion rent collected and TR payouts, there is a third input to the TR Clearing Account—TR auction revenues. TR auction revenues are the proceeds from selling TRs (a payment into the TR Clearing Account). Due to Ontario's two-schedule price system,[23] transaction failures and intertie de-ratings, there are congestion events in which a congestion rent

[23] Intertie congestion (and thus the ICP and TR payouts) is calculated based on the pre-dispatch unconstrained schedule, while congestion rent collected is based on the real-time constrained schedule. To the degree that the pre-dispatch unconstrained schedule differs from the real-time constrained schedule, TR payouts may differ from congestion rent collected. In the extreme, congestion may occur in one direction (*e.g.* import) in the pre-dispatch unconstrained schedule, but the real-time constrained schedule has net transactions in the opposite direction (*e.g.* export). In this case, import TR payouts are made and negative import congestion rents are "collected".

shortfall arises; instead of remaining revenue neutral, these events draw down the TR Clearing Account. These shortfalls are covered primarily by TR auction revenues. The Panel has previously expressed the view that TR auction revenues should be for the benefit of consumers in the form of a reduction in transmission charges.[24] In that context, every dollar of congestion rent shortfall represents a dollar that does not accrue to the benefit of Ontario customers.

Note that interties with a high frequency of import congestion hours (see Figure 2-15) do not necessarily correlate with high import TR payouts and import congestion rent, primarily because of the differences in intertie capacity (and thus TRs sold) at each intertie.

Commentary and Market Consideration:

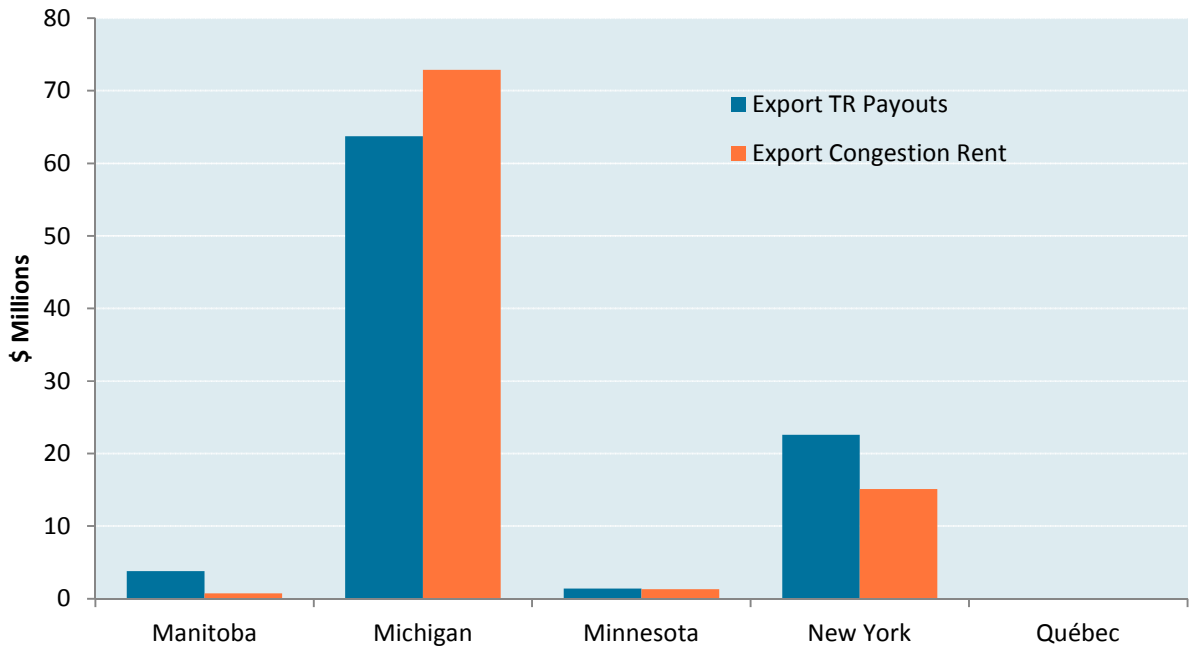
In the Summer 2016 Period, TR payouts exceeded import congestion rent collected by $350,000 across all interties; a relative balance when compared to past reporting periods. TR payouts exceeded congestion rents primarily at the Manitoba interface, in part due to the high failure rate of import transactions on the Manitoba interface (see Table 2-7).

Figure 2-18: Export Congestion Rent & TR Payouts by Interface Group
May 2016 – October 2016
($)

Description:

Figure 2-18 compares the total export congestion rent collected to total TR payouts by interface group for the Summer 2016 Period.

[24] If there were no TRs in Ontario, but all other aspects of the market design were retained, congestion rent would still be collected by the IESO whenever there was congestion on an intertie. Those congestion rents are the price importers and exporters are prepared to pay for scarce transmission capacity, suggesting that rents might be paid to transmission owners. But as the transmission companies are rate-regulated entities, any congestion rents paid to them would presumably be used to offset their regulated revenue requirement. Thus, their customers (Ontario consumers) would benefit from congestion rents. For more information on the TR market and the basis for disbursing funds from the TR Clearing Account to offset transmission service charges, see pages 146-160 of the Panel's January 2013 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2011-Apr2012_20130114.pdf



Relevance:

When there is export congestion, the intertie zonal price is greater than the Ontario price. See the Relevance section associated with Figure 2-17 which describes the relationship between congestion rents and TR payments in regards to import congestion.

Commentary and Market Consideration:

Across all interfaces, export TR payouts were in excess of congestion rent collected by $1.5 million. The Michigan interface, which was the most heavily export-congested interface in the Summer 2016 Period (see Figure 2-16), saw congestion rents collected exceed TR payouts by $9.1 million, while conversely the New York interface saw TR payouts exceeding congestion rents collected by $7.5 million.

Manitoba experienced a shortfall in congestion rents of $3.1 million. Manitoba also experienced the highest rate of export failures during the Summer 2016 Period (see Table 2-6) which contributed to the under collection of congestion rents. If a scheduled export transaction fails in an hour where congestion existed, congestion rent goes uncollected as no energy is purchased, though the transaction contributed to congestion at the interface in pre-dispatch. The Panel has previously recommended that traders that fail transactions for reasons within their control should

be required to pay the foregone congestion rent, thus maintaining the balance in the TR Clearing Account.[25]

Table 2-4: Average Long-Term (12-month) TR Auction Prices by Interface and Direction November 2015 – October 2016 ($/MW)

Description:

Table 2-4 lists the average auction prices for one megawatt of long-term (12-month) TRs sold for each interface, in either direction, since November 2015 (these TRs would have been valid during the Summer 2016 Period).

Direction	Auction Date	Period TRs are Valid	Manitoba	Michigan	Minnesota	New York	Québec
Import	Nov-15	Jan-16 to Dec-16	1,735	389	3,707	224	1,850
	Feb-16	Apr-16 to Mar-17	1,796	339	3,487	208	1,118
	May-16	Jul-16 to Jun-17	1,437	350	1,564	252	1,259
	Aug-16	Oct-16 to Sep-17	2,208	164	3,006	384	2,662
Export	Nov-15	Jan-16 to Dec-16	8,828	61,875	19,034	29,036	4,383
	Feb-16	Apr-16 to Mar-17	19,595	78,135	25,276	34,165	2,980
	May-16	Jul-16 to Jun-17	31,341	113,934	42,647	48,881	3,726
	Aug-16	Oct-16 to Sep-17	29,144	101,732	30,813	40,548	3,256

Relevance:

If an auction is efficient, the price paid for one megawatt of TRs should reflect the expected payout from owning that TR for the period. This is equivalent to the expected sum of all ICPs in the direction of the TR over the period for which the TR is valid. The greater the expected frequency and/or magnitude of congestion on the intertie, the more valuable the TR. Assuming an efficient auction, auction revenues signal market participant expectations of intertie congestion conditions for the forward period.

Commentary and Market Consideration:

With the exception of the Québec interface, long-term export TR prices have increased significantly since the November 2015 auction, indicating that TR holders expected that export

[25] See the Panel's May 2017 Monitoring Report, pages 78-81, available at: https://www.oeb.ca/sites/default/files/msp-report-nov2015-apr2016_20170508.pdf. As noted in chapter 1, the IESO has indicated that it would review this matter and determine an appropriate avenue to address the issue.

congestion on the interties would not only persist but likely increase through to the summer of 2017. In the four auctions held from November 2015 to August 2016, the highest prices were for long-term export TRs on the Michigan interface ($113,934/MW); true to expectations, the export direction on the Michigan intertie experienced the most frequent and costly congestion of all the interties in the Summer 2016 Period.

Table 2-5: Average Short-Term (One-month) TR Auction Prices by Interface and Direction November 2015 – October 2016 ($/MW)

Description:

Table 2-5 lists the auction prices for one megawatt of short-term (one-month) TRs sold at each interface, in either direction, since November 2015.

Direction	Period TRs are Valid	Manitoba	Michigan	Minnesota	New York	Québec
Import	Nov-15	165	15	122	15	5
	Dec-15	117	0	201	0	28
	Jan-16	103	0	327	1	20
	Feb-16	121	0	143	0	28
	Mar-16	98	0	126	0	40
	Apr-16	113	14	130	0	82
	May-16	78	16	211	1	210
	Jun-16	87	12	79	11	21
	Jul-16	97	19	87	4	35
	Aug-16	67	1	113	15	112
	Sep-16	150	2	162	30	203
	Oct-16	126	15	124	8	351
Export	Nov-15	310	4,009	-	2,297	72
	Dec-15	457	4,494	-	1,208	220
	Jan-16	1,001	4,621	-	1,305	826
	Feb-16	1,510	6,145	-	1,655	355
	Mar-16	2,612	7,373	-	2,875	186
	Apr-16	2,320	6,586	-	1,523	10
	May-16	3,050	8,005	-	1,488	16
	Jun-16	3,626	8,656	4,233	4,380	50
	Jul-16	4,133	10,848	-	3,085	8
	Aug-16	2,020	5,394	2,334	2,664	3
	Sep-16	720	7,395	1,001	2,269	7
	Oct-16	2,002	11,108	-	2,305	8

Relevance:

As discussed in the Relevance section associated with Table 2-4, auction revenues signal market participant expectations of intertie congestion conditions for the forward period.

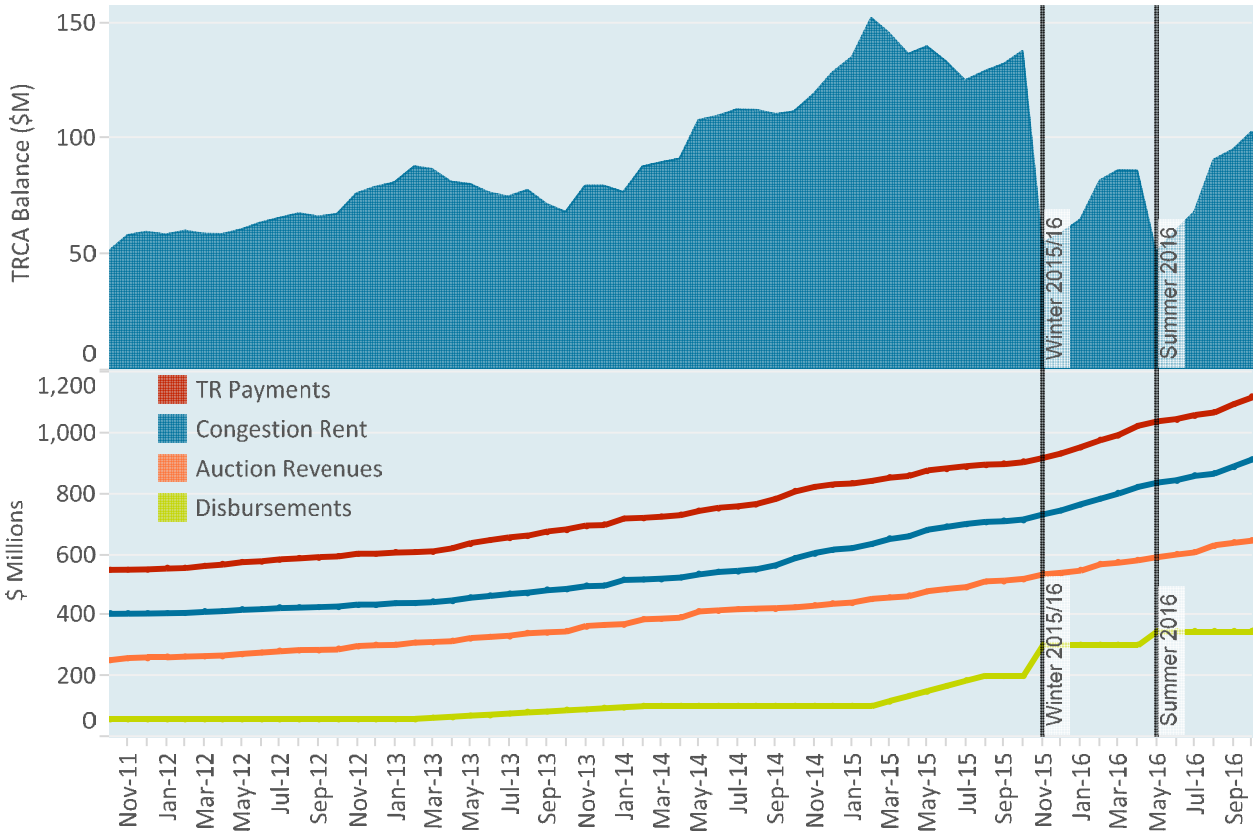
Commentary and Market Consideration:

Short-term auction prices in the Summer 2016 Period were reflective of the relative frequency of congestion experienced at each interface. Import TRs were consistently cheaper than export TRs due to the net export position in which Ontario routinely finds itself; Michigan had the most frequently congested interface (see Figure 2-16) and the highest TR auction prices throughout the Summer 2016 Period.

Figure 2-19: Transmission Rights Clearing Account
November 2011 – October 2016
($)

Description:

The TR Clearing Account is an account administered by the IESO to record various amounts related to TRs. Figure 2-19 shows the estimated balance in this account at the end of each month for the previous five years, and well as a breakdown by its component transactions.



Relevance:

The TR Clearing Account balance is affected by five types of transactions:

Credits

- Congestion rent received from the market
- TR auction revenues
- Interest earned on the TR Clearing Account balance

Debits

- TR payouts to TR holders
- Disbursements to Ontario market participants

Tracking TR Clearing Account transactions over a period of time provides an indication of the health of the TR market and the policies that govern it. The account has a reserve threshold of $20 million set by the IESO Board of Directors; funds in excess of this threshold are intended to be disbursed to wholesale loads and exporters semi-annually or as directed by the IESO Board of Directors.

Commentary & Market Considerations:

In the Summer 2016 Period, the balance in the TR Clearing Account increased by $18 million, from $85 million at the end of the Winter 2015/16 Period, to $103 million, $83 million above the Reserve Threshold. This change was composed of:

- $156 million in revenue:
  - $91 million in congestion rent collected
  - $65 million in auction revenues
  - $0.2 million in interest
- $138 million in disbursements:
  - $93 million in TR payments to rights holders
  - $45 million in disbursements to Ontario consumers[26]

Total congestion rent shortfall for the period was approximately $1.86 million, representing money that was paid to intertie traders. While the sum remains significant, it represents a significant improvement from the $13 million in congestion rent shortfall experienced during the Winter 2015/2016 Period.

2 *Demand*

This section discusses Ontario energy demand for the Summer 2016 Period relative to previous years.

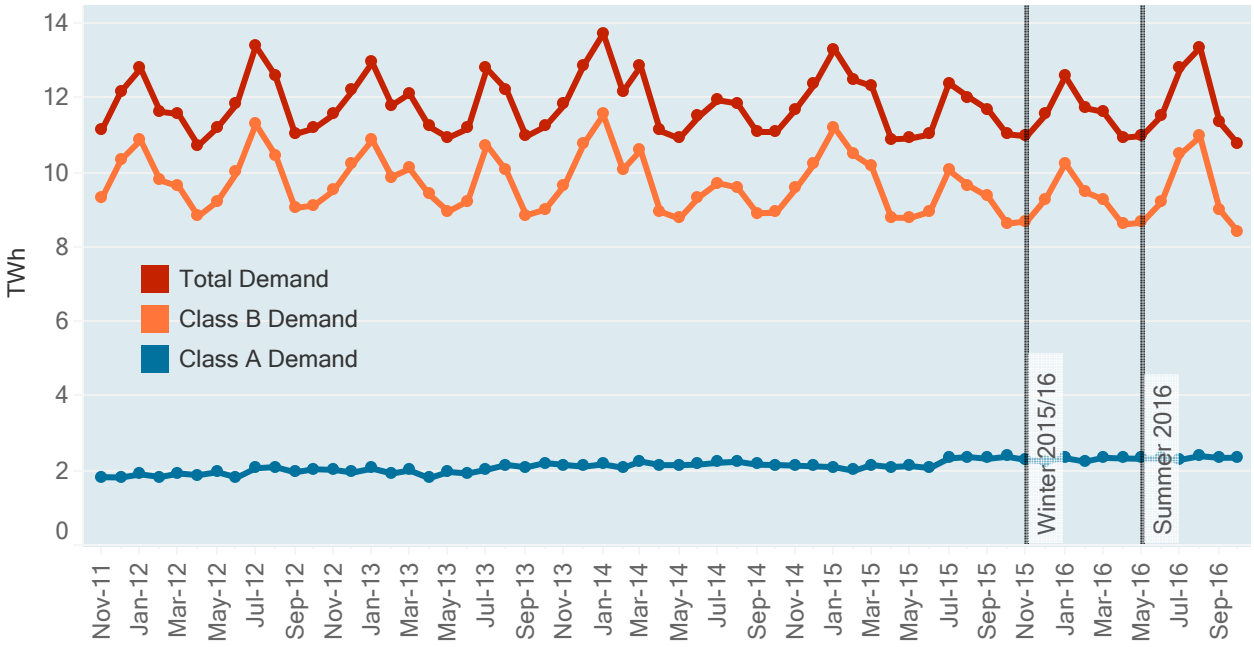
Figure 2-20: Monthly Ontario Energy Demand by Class A and Class B Consumers
November 2011 – October 2016
(TWh)

Description:

Figure 2-20 displays energy consumption by all Ontario consumers in each month of the past five years, broken down by demand from Class A and Class B consumers. The Figure represents total Ontario demand – not grid-connected demand – in that it includes demand satisfied by embedded generators.[27]

[26] On June 2, 2016, the IESO announced a lump sum disbursement from the TR Clearing Account of $45 million that was to occur during the June 2016 billing cycle: http://www.ieso.ca/sector-participants/ieso-news/2016/06/transmission-rights-clearing-account-disbursement

[27] Monthly embedded Class A consumption data may be understated as available data does not identify the quantity of behind-the-meter generation by consumer class. For more information, see pages 105-109 of the Panel's April 2015 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2013-Apr2014_20150420.pdf



Relevance:

Ontario monthly consumption information shows seasonal variations in consumption and year-to-year changes in consumption patterns. The breakdown of consumers into Class A and Class B helps identify their respective monthly demand profiles.

Commentary and Market Consideration:

The peak monthly consumption during the Summer 2016 Period was 13.4 TWh, which was the highest monthly peak since the November 2013 – April 2014 winter period when Ontario was experiencing an abnormally cold winter. Total demand during the Summer 2016 Period was 70.7 TWh, a modest increase in demand from the Summer 2015 Period due to above normal temperatures.

Seasonal changes in Ontario demand are attributed almost entirely to Class B consumers, which include residential, small and medium commercial and small industrial loads. Demand from Class A consumers, a group primarily composed of industrial loads and large commercial consumers, exhibit little of the seasonality evident from Class B consumers.

3 *Supply* [28]

During the second and third quarters of 2016, 119 MW of nameplate generating capacity was added to the IESO-controlled grid. This new grid-connected capacity consisted of gas (0.8 MW), wind (99.3 MW) and hydro (18.9 MW) generation. At the end of the third quarter of 2016, grid connected generation capacity totalled 36,070 MW, consisting of nuclear (12,978 MW), gas-fired (9,934 MW), hydroelectric (8,451 MW), wind (3,923 MW), biofuel (495MW) and solar generation (280 MW).[29]

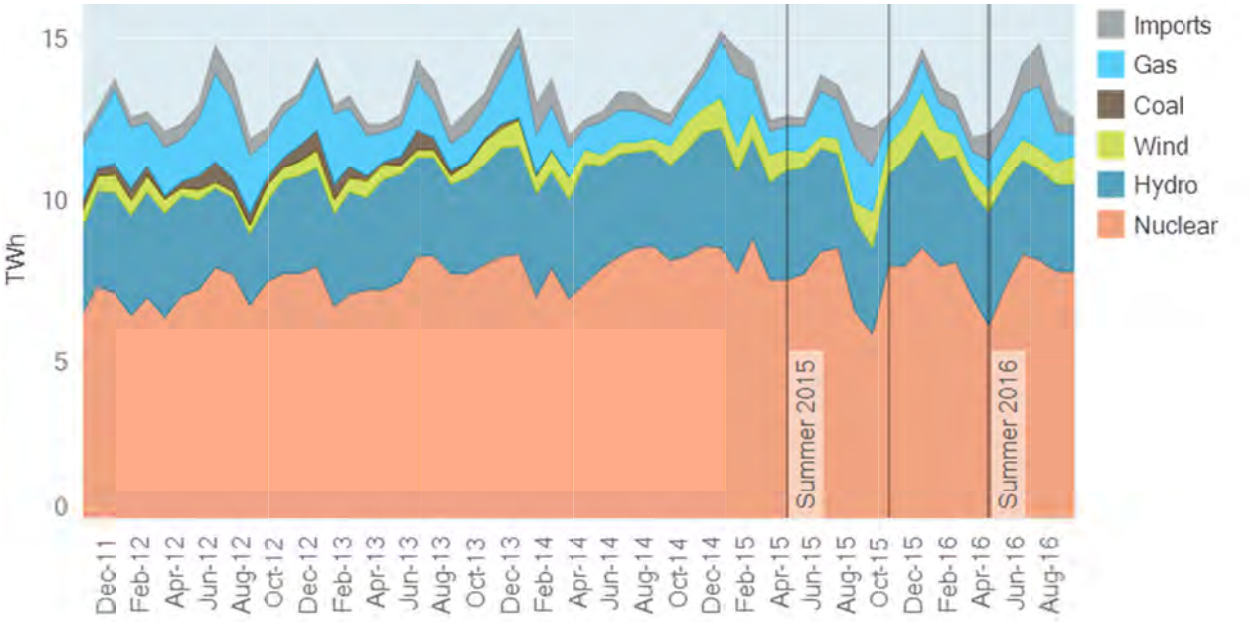
During the second and third quarters of 2016, 146 MW of nameplate IESO-contracted generating capacity was added at the distribution level. This new distribution-level capacity (or 'embedded' capacity) consisted of solar (50 MW), wind (36 MW), gas-fired and combined heat and power (46 MW) and energy from waste (14 MW). At the end of the third quarter of 2016, IESO-contracted embedded capacity totalled 3,119 MW, consisting of solar (1,926 MW), wind (534 MW), hydroelectric (268 MW), gas-fired and combined heat and power (259 MW), biofuel (108 MW) and energy from waste (24 MW).[30]

Figure 2-21: Resources Scheduled in the Real-Time Market (Unconstrained) Schedule
November 2011 – October 2016
(TWh)

Description:

Figure 2-21 displays the share of real-time unconstrained production schedules from November 2011 to October 2016 by resource or transaction type: wind, coal, gas-fired, hydroelectric, nuclear and imports. Solar and biofuel are excluded from the figure as they contribute minimally to the total grid-connected resources scheduled in real-time.

[28] A more detailed examination of medium-term supply capacity in Ontario is available from the IESO's regularly-published 18-month outlooks, available at: http://www.ieso.ca/sector-participants/planning-and-forecasting/18-month-outlook
[29] Capacity totals were obtained from the IESO 18 month outlook reports which can be found at: http://www.ieso.ca/sector-participants/planning-and-forecasting/18-month-outlook.
[30] Embedded capacity additions and totals were obtained from the quarterly Ontario Energy Reports, which can be found at: http://www.ontarioenergyreport.ca/index.php.



Relevance:

This figure displays the evolution of Ontario's changing mix of real-time energy supply. Changes in the resources scheduled may be the result of a number of factors, such as changes in energy policy or seasonal variations (for example, during the spring snowmelt or 'freshet' when hydroelectric plants have an abundant supply of fuel).

Commentary and Market Considerations:

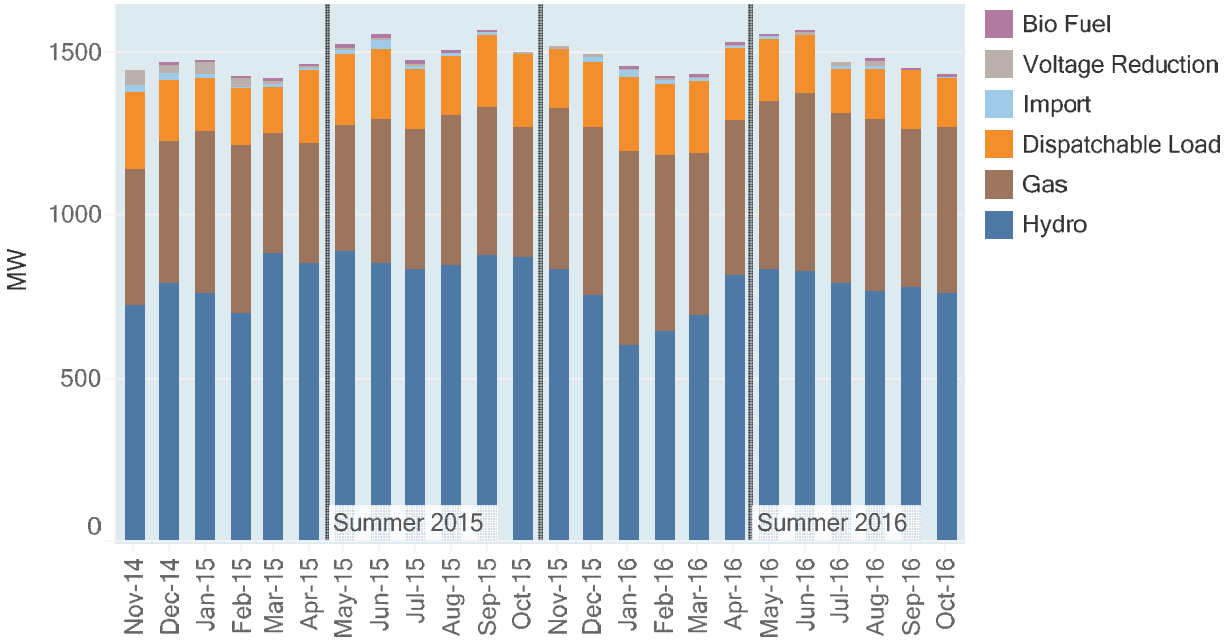
Comparing the Summer 2016 and Summer 2015 Periods, the composition of resources scheduled to meet demand in the unconstrained schedule was largely unchanged, save for a modest increase in the quantity of imports scheduled.

Figure 2-22: Average Hourly Operating Reserve Scheduled by Resource Type
November 2014- October 2016
(MW)

Description:

Figure 2-22 displays the share of real-time unconstrained OR schedules from November 2014 to October 2016 by resource or transaction type: hydroelectric, gas-fired, imports, dispatchable

loads, and voltage reduction (taken as a control action by the IESO).[31] Changes in the total average hourly operating reserve scheduled reflect changes in the OR requirement over time.



Relevance:

This figure reflects the evolution in Ontario's changing mix for OR supply as well as changes in the OR requirement over time. Changes in scheduled OR may result from a variety of factors such as changes in energy policy or seasonal variations, while changes to the OR requirement may result from changes in grid configuration and outages, among other factors.[32]

Commentary and Market Considerations:

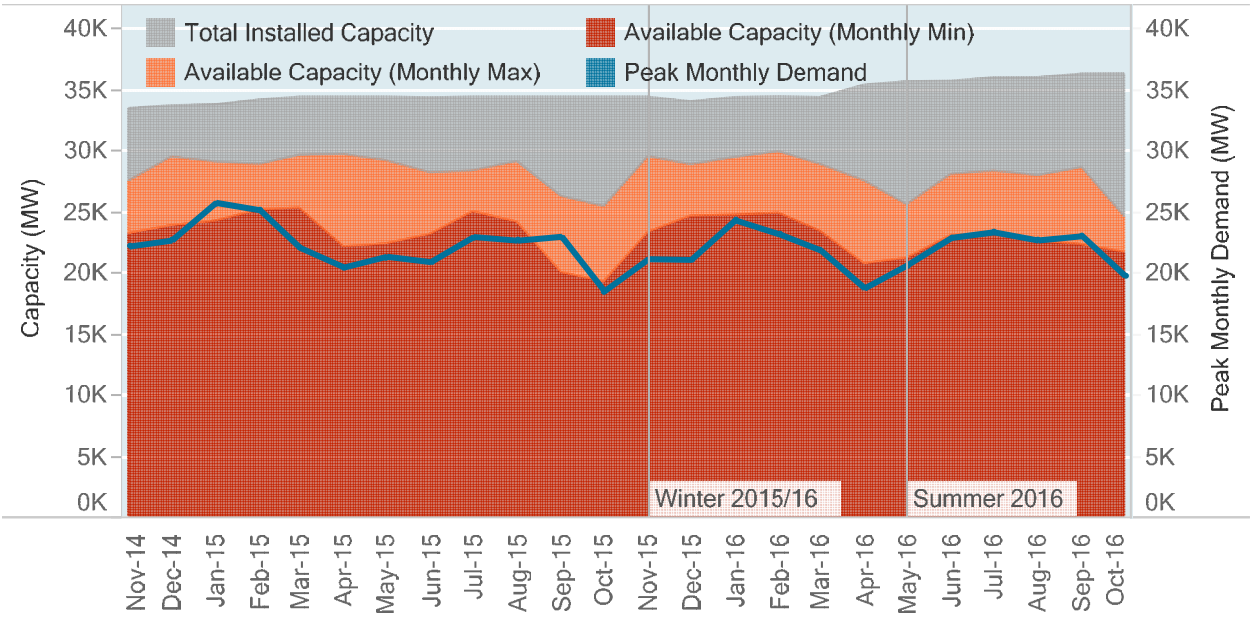
The amount of OR scheduled in the Summer 2016 Period remained stable relative to the Summer 2015 Period. The composition of resources scheduled for OR changed slightly: the amount of OR supplied by gas-fired resources increased by 7% while the amount supplied by hydroelectric and dispatchable load resources combined fell by 6%. Imports, biofuel and voltage reduction continued to play a minor role, together contributing less than 1% of the total OR scheduled.

[31] The IESO inserts standing offers in the OR offer stack that represent the IESO's ability to use 3% and 5% voltage reductions or forego the 30-minute OR requirement (under specific conditions) to meet OR needs. The offers have a pre-defined price and quantity and are only scheduled in real-time, never in pre-dispatch. Voltage reductions are an out-of-market control action taken by the IESO when the market cannot provide enough supply to meet forecasted demand and reserve requirements.
[32] The total energy available from the 10-minute OR market must be enough to cover the single largest contingency on Ontario's electricity grid, with at least 25% of that energy available as 10-minute spinning reserve. The total energy available from the 30-minute OR market must be enough to cover half the second largest contingency on Ontario's grid.

Figure 2-23: Unavailable Generation Relative to Installed Capacity
November 2014 – October 2016
(MW)[33]

Description:

Figure 2-23 plots the monthly minimum and maximum available capacity, accounting for unavailable generation capacity due to planned and forced (i.e. unforeseen) outages and de-rates, unavailable capacity from intermittent and self-scheduling generators and constrained generation capacity due to operating security limits from November 2014 to October 2016. For reference, the figure also includes the monthly peak market demand, excluding imports. [34]



Relevance:

The availability of generating capacity and the size of the supply cushion are key factors in determining market prices.

[33] Until the May 2017 Monitoring Report, this figure reported planned and forced outages and derates relative to capacity. The Panel revised the methodology by which it reports on unavailable generation capacity to also include unscheduled capacity from self-scheduling resources and capacity that is made unavailable due to security limits on the high-voltage grid, in addition to planned and forced outages and derates. In addition, the manner of reporting unavailable generation capacity has changed; it is no longer reported as a percentage of capacity. As such, the data reported in this figure will not align with similar data published in previous Panel reports.

[34] Unavailable generation capacity data was obtained from adequacy reports published daily by the IESO. The maximum and minimum hours of the month were used. Daily, weekly and monthly market summaries published by the IESO can be found om the IESO website, available at: http://www.ieso.ca/power-data/market-summaries-archive

Commentary and Market Considerations:

An increase in planned outages for nuclear and gas generation facilities were the main reason for outages reaching 40% of installed capacity by the end of the Summer 2016 Period. Three nuclear reactors underwent planned maintenance and the refurbishment of Darlington Unit 2 began in mid-October.

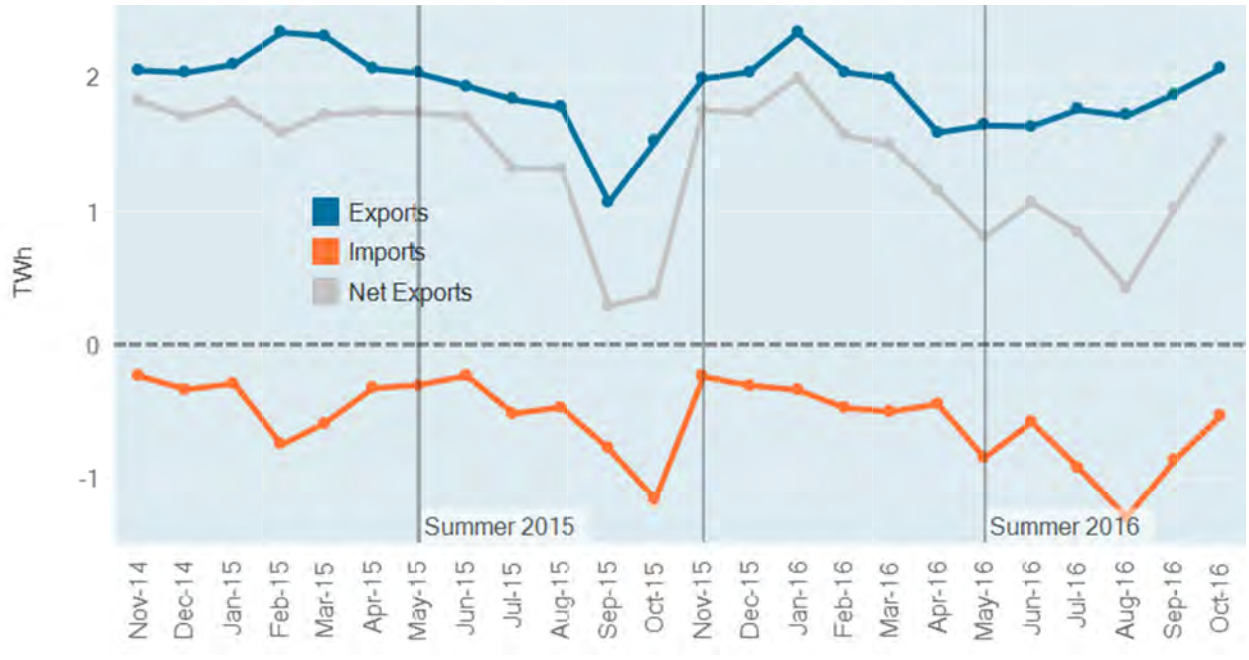
4 *Imports, Exports and Net Exports*

The data used in this section is based on the unconstrained sequence as schedules in this sequence directly affect market prices. The unconstrained schedules may not reflect actual power flows.[35]

Figure 2-24: Total Monthly Imports, Exports & Net Exports
November 2014 – October 2016
(TWh)

Description:

Figure 2-24 plots total monthly imports, exports and net exports from November 2014 to October 2016. Exports are represented by positive values while imports are represented by negative values.



[35] Although the constrained schedules provide a better picture of actual flows of power on the interties, they do not provide information on intertie congestion prices or the Ontario uniform price.

Relevance:

Imports and exports play an important role in determining supply and demand conditions in the province, and thus affect the market price. Tracking net export transactions over time provides insight into supply and demand conditions in Ontario relative to neighbouring jurisdictions. Periods of sustained net exports, such as the Summer 2016 Period, indicate times of relative energy surplus in Ontario, while sustained periods of net imports, such as during the mid-2000s, indicate periods of relative scarcity.

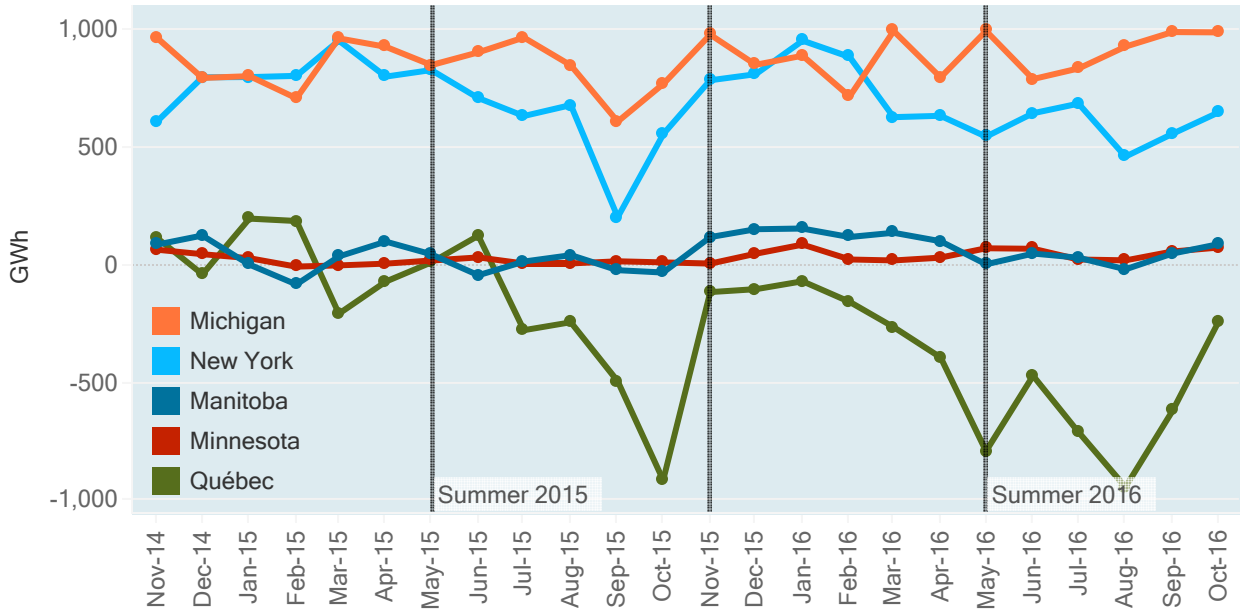
Commentary and Market Considerations:

Ontario was a net exporter in each month of the Summer 2016 Period, totalling 5.7 TWh, down from 6.7 TWh in the Summer 2015 Period. High Ontario demand in August 2016 resulted in total imports reaching the highest monthly import total over the last two years. As was the case in the Summer 2015 Period, Québec was the primary source of imports (see Figure 2-25).

Figure 2-25: Net Exports by Interface Group
November 2014 – October 2016
(GWh)

Description:

Figure 2-25 presents a breakdown of net exports from November 2014 to October 2016 for each of Ontario's five neighboring jurisdictions: Manitoba, Michigan, Minnesota, New York and Québec. Net exports are represented by positive values while net imports are represented by negative values.



Relevance:

This figure shows how Ontario's energy trading with each external jurisdiction evolves over time.

Commentary and Market Considerations:

During the Summer 2016 Period, both the Québec and Michigan interfaces had monthly totals representing two year highs. Québec was a net importer delivering a high of 946 GWh in August, and Michigan was a net exporter reaching a high of 993 GWh in May (and nearly achieving that high again in August and September).

Compared to the Summer 2015 Period, net exports at the Michigan, Minnesota, Manitoba and New York interfaces were all higher, together increasing by 786 GWh, while net imports from Québec more than doubled to 1,862 GWh. All told, net exports decreased by just over 1 TWh.

Table 2-6: Average Monthly Export Failures by Interface Group and Cause
Winter 2015/16 & Summer 2016 Periods
(GWh and %)

Description:

Table 2-6 reports average monthly export curtailments and failures over the Summer 2016 and Winter 2015/16 Periods by interface group and cause. The failure and curtailment rates are

expressed as a percentage of total (constrained) exports over each interface, excluding linked wheel transactions.[36]

Interface Group	Average Monthly Exports (GWh)		Average Monthly Export Failure and Curtailment (GWh)				Export Failure and Curtailment Rate (%)			
			ISO Curtailment		MP Failure		ISO Curtailment		MP Failure	
	Summer 2016	Winter 2015/16	Summer 2016	Winter 2015/16	Summer 2016	Winter 2015/16	Summer 2016	Winter 2015/16	Summer 2016	Winter 2015/16
New York	277.8	386.3	1.0	1.8	5.7	8.3	0.4	0.5	2.0	2.1
Michigan	326.3	348.1	1.4	1.5	4.7	3.2	0.4	0.4	1.4	0.9
Manitoba	50.6	79.9	3.7	2.6	14.8	16.3	7.2	3.2	29.1	20.4
Minnesota	20.4	6.0	0.6	0.2	0.5	0.2	2.7	2.7	2.6	3.7
Québec	60.6	93.2	0.6	4.2	0.4	1.3	1.1	4.5	0.7	1.4

Relevance:

Curtailment (ISO Curtailment) refers to an action taken by a system operator, typically for reliability or security reasons. Failure (MP Failure), on the other hand, refers to a transaction that fails for reasons within the control of the market participant (such as a failure to obtain transmission service).

Failed or curtailed exports reduce demand between PD-1 and real-time. These short-notice changes in demand can lead to a sub-optimal level of intertie transactions given the market prices that prevail in real-time, and may contribute to Surplus Baseload Generation conditions. The IESO may dispatch down domestic generation or curtail imports to compensate for MP Failures or ISO Curtailments.

Commentary and Market Considerations:

The Manitoba interface continues to experience an MP failure percentage that far exceeds the failure rate experienced at other interties: 29.1% in the Summer 2016 Period versus 20.4% in the Winter 2015/16 Period and 31.1% in the Summer 2015 Period.

[36] A linked wheel transaction is one in which an import and an export are scheduled in the same hour, thus wheeling energy through Ontario.

Table 2-7: Average Monthly Import Failures by Interface Group and Cause
Winter 2015/16 & Summer 2016 Periods
(GWh and %)

Description:

Table 2-7 reports average monthly import failures and curtailments over the Summer 2016 and Winter 2015/16 Periods by interface group and cause. The MP Failure and ISO Curtailment rates are expressed as a percentage of total imports, excluding linked wheel transactions.

Interface Group	Average Monthly Imports GWh		Average Monthly Import Failure and Curtailment GWh				Import Failure and Curtailment Rate %			
			ISO-Curtailment		MP-Failure		ISO-Curtailment		MP-Failure	
	Summer 2016	Winter 2015/16	Summer 2016	Winter 2015/16	Summer 2016	Winter 2015/16	Summer 2016	Winter 2015/16	Summer 2016	Winter 2015/16
New York	20.9	1.4	0.1	0.0	0.2	0.1	0.4	0.6	1.1	3.8
Michigan	5.9	1.2	0.1	0.2	1.6	0.4	1.1	16.6	27.5	34.7
Manitoba	28.4	34.8	5.6	5.9	0.4	0.3	19.7	16.9	1.3	0.8
Minnesota	2.0	8.2	0.1	0.9	0.2	0.7	7.4	11.5	11.8	8.8
Québec	196.5	85.7	2.5	2.6	0.2	0.1	1.3	3.1	0.1	0.1

Relevance:

Failed or curtailed imports reduce supply between the PD-1 and real-time. This change in supply can lead to a sub-optimal level of intertie transactions and may contribute to increases in price. The IESO may dispatch up domestic generation or curtail exports to compensate for MP Failures and ISO Curtailments.

Commentary and Market Considerations:

The average monthly import quantity from Québec has increased to 197 GWh, significantly higher than the 86 GWh and 136 GWh experienced during the Winter 2015/16 and Summer 2015 Periods, respectively. Despite the increase, curtailment quantities and rates on the Québec interface were lower than in the previous two reporting periods.

Michigan continues to experience a high MP Failure rate on relatively low volumes, at 27.5% in the Summer 206 Period.

Chapter 3: Analysis of Anomalous Market Outcomes

1 *Introduction*

This chapter examines the market outcomes associated with anomalous prices and payments from May 1, 2016 to October 31, 2016 (Summer 2016 Period), making comparisons to the May 1, 2015 to October 31, 2015 period (Summer 2015 Period) as appropriate.

Traditionally, the Panel's analysis of anomalous events has focussed on high and negative Hourly Ontario Energy Prices (HOEP), as well as instances of high uplift such as Congestion Management Settlement Credit (CMSC) payments and Intertie Offer Guarantee (IOG) payments. More recently, the Panel has also reported on payments made under the Real-Time Generation Cost Guarantee (RT-GCG) program and the Day-Ahead Commitment Program (DACP) where they are of particular interest. Payments made under the DACP are referred to as Day-Ahead Production Cost Guarantee (DA-PCG) payments. All of the above payments are recovered from consumers (and exporters) through uplift charges.

The Panel has established a number of thresholds to identify anomalous events. Table 3-1 displays the number of events that exceeded the Panel's thresholds during the Summer 2016 Period, with comparisons to the Summer 2015 Period.

Table 3-1: Summary of Anomalous Events
May 2016 – October 2016 & May 2015 – October 2015
(Number of Events)

Anomalous Event Threshold	Number of Events May 1, 2016 to October 31, 2016	Number of Events May 1, 2015 to October 31, 2015
HOEP > $200	13	9
HOEP ≤ $0	735	452
Energy CMSC > $1 million/day	7	0
Energy CMSC > $500,000/hour	1	0
OR Payments > $100,000/hour	20	15
IOG > $1 million/day	0	0
IOG > $500,000/hour	0	0

1.1 *Summary of High-Price Hours*

During the Summer 2016 Period, there were 13 hours when the HOEP was greater than $200/MWh; in 10 of these 13 hours, there were also operating reserve (OR) payments in excess

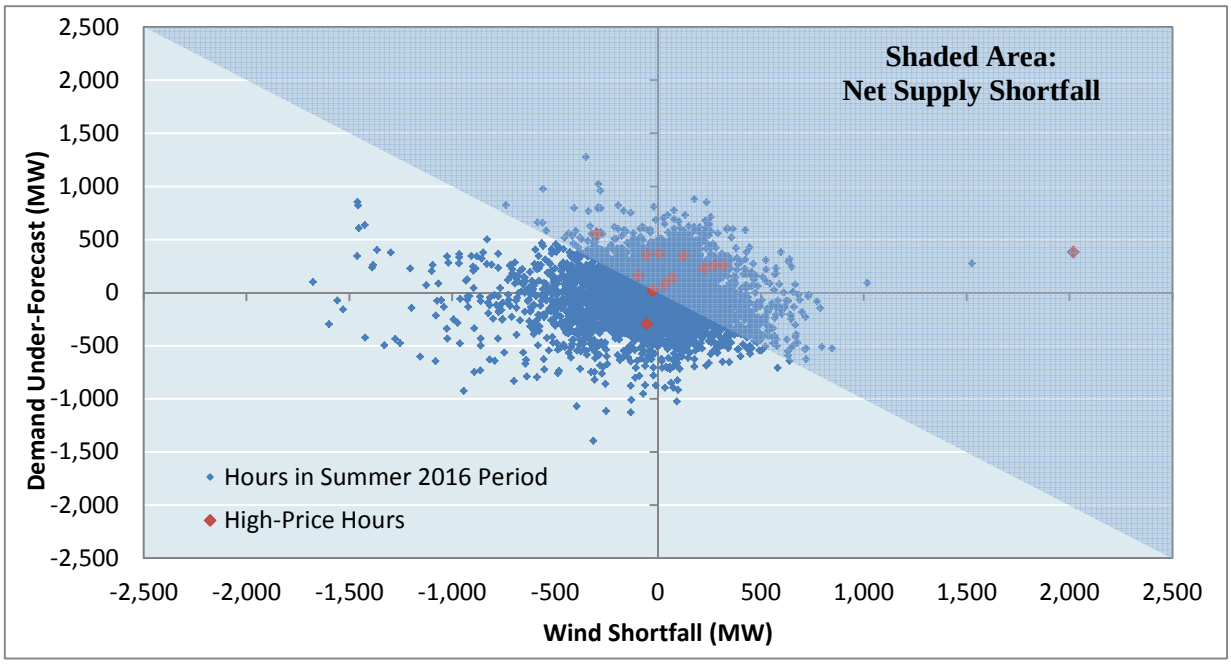
of $100,000. Having analyzed these hours, the Panel has concluded they were largely the result of the following:

- Relatively high market demand;
- Variable generation shortfall (actual output below the forecast); and
- Demand forecast errors.

In these hours, ample supply conditions in pre-dispatch resulted in relatively low prices and few gas-fired facilities being committed to generate. With few gas-fired facilities online to provide relatively inexpensive ramping capability and OR, the system had limited ability to respond to the shortfall of variable generation and the increase in demand that occurred from pre-dispatch (PD-1) to real-time, resulting in high HOEPs and high OR payments. These circumstances contributed to the two highest-priced hours in the Summer 2016 Period: on June 9, 2016, the HOEP for Hour Ending (HE) 20 and HE 21 was $1,619.60/MWh and $1,327.89/MWh respectively.

As illustrated in Figure 3-1, almost all 13 high-price hours, marked in red, occurred during net supply shortfall conditions (defined as hours in which the sum of demand under-forecast and variable generation shortfall are positive, creating tighter supply conditions in real-time relative to PD-1).

Figure 3-1: HOEP by Net Supply Conditions
May 2016 – October 2016
(MW)



In one of the hours during which there was a net supply shortfall (HE 19 on October 23, 2016), a manual error made by the IESO in the operation of the pre-dispatch wind forecasting tool overstated the variable generation shortfall by more than 1,540 MW. While this error had the initial effect of driving the HOEP to an artificially high level, the IESO corrected the forecast and administratively lowered the HOEP for the hour to $257/MWh after the fact.

There were also two high-price hours that did not take place in net supply shortfall conditions. The first was HE 17 on September 6, 2016. In this hour, conditions from PD-1 to real-time remained fairly consistent, with a modest net supply excess of 6 MW. Nevertheless, high Ontario demand above 22,000 MW and a thin supply cushion necessitated the dispatch of more expensive hydroelectric generation for half the hour, which resulted in an HOEP of $201.31/MWh.

The second was HE 18 on September 26, 2016. In contrast to the other high-price hours, during this hour there was initially a relatively large net supply excess of 350 MW in real-time relative to PD-1. While such excess supply conditions typically correspond to a lower HOEP than the PD-1 Market Clearing Price (MCP), in this instance the HOEP was ultimately much higher at

$332.39/MWh. The increase in price from PD-1 to real-time was the result of a loss of generation that materialized from interval 8 to interval 9 of HE 18, when the energy MCP and OR MCP increased from below $100/MWh to $1999.99/MWh. The loss of supply was in part the result of a hydroelectric facility that was de-rated by 173 MW in interval 9. Additionally, an issue with the IESO's wind forecasting tool resulted in wind output appearing artificially high in the unconstrained schedule during HE 18, resulting in artificially supressed prices for the first eight intervals. In interval 9 of that hour, the quantity of artificial supply decreased to more accurately reflect actual wind output, putting upward pressure on price. Compensating for this loss of supply in five minutes required scheduling higher-priced gas-fired resources from the energy and OR market, resulting in the high-price hour.

1.2 *Summary of Low-Price Hours*

There were 735 hours when the HOEP was non-positive (zero or negative) during the Summer 2016 Period, an increase relative to the Summer 2015 Period when there were 452 such hours. A non-positive HOEP may arise as a result of low Ontario demand, failed export transactions or abundant supply offered at negative prices, among other causes. A contributor to the increase in non-positive price hours during the Summer 2016 Period was the addition of more wind and solar capacity, which offers energy at non-positive prices. Between the Summer 2015 Period and the Summer 2016 Period, 829 MW of new grid-connected wind and solar capacity was added.

1.3 *Summary of Anomalous Uplift Payments*

In the Summer 2015 Period, there were no days or hours in which the Panel's CMSC and IOG thresholds were exceeded. The same is true of IOG payments in the Summer 2016 period. However, there were eight anomalous CMSC events in the Summer 2016 Period.

There was one hour during the Summer 2016 Period with more than $500,000 in CMSC payments: in HE 1 on July 23, 2016, there was $518,557 in CMSC payments, most of which was the result of ramp-down CMSC paid to a generator.[37]

[37] In section 2.2 of Chapter 3 of the Panel's May 2017 Monitoring Report, the Panel estimated that CMSC payments caused by ramp down would have been reduced by $1.9 million from June 25, 2015 to December 7, 2016 (including the hour noted here) if the market rule change had taken effect on June 24, 2015 when the change was approved. However, implementation of the market rule change was delayed to December 8, 2016 due to the relative complexity of the required IT solution.

Table 3-2 presents the seven instances of CMSC payments that exceeded the Panel's daily CMSC threshold of $1,000,000.

Table 3-2: CMSC Payments Exceeding the Panel's Daily CMSC Threshold
May 2016 – October 2016
($)

Date	CMSC Payments
2016/07/23	$2,164,848
2016/07/24	$1,778,072
2016/08/04	$1,648,947
2016/08/10	$1,580,464
2016/08/11	$1,462,285
2016/09/07	$1,142,533
2016/08/13	$1,087,558

The high CMSC payments on July 23, 2016 and July 24, 2016 were partially the result of a single dispatchable load (Load A) receiving significant constrained-off CMSC payments. On July 23, Load A received $942,168 in constrained-off CMSC payments (43.5% of the daily total CMSC); on July 24, the same load received another $1,082,089 in constrained-off CMSC payments (60.9% of the daily total CMSC). The IESO had informed Load A in HE 20 of July 21 that the circuits in its vicinity would be on outage for several days, but despite being aware that its energy consumption would be limited by grid conditions Load A bid at $1,999/MWh, thereby maximizing its constrained-off CMSC payments for the duration of the outage.

On August 4, 2016, CMSC payments amounted to $1,648,947. During this day, hourly Ontario demand was relatively high from HE 8 to HE 23, with a peak demand of 22,521 MW in HE 18. As a result, a gas-fired facility with high-priced energy offers (above $200/MWh) was constrained on in order to relieve a zone with thermal line limit concerns, resulting in over $430,000 in CMSC payments throughout the day. The remainder of the CMSC payments were paid to various domestic resources and intertie traders that received less than $100,000 each.

The remaining four high CMSC days all experienced high Ontario demand well above 20,000 MW, which led to transmission constraints resulting in CMSC payments to multiple market participants for various measures such as constraining on domestic generation and curtailing exports in real-time. In another instance, as discussed in Section 2.1, an equipment concern at a dispatchable load resulted in significant constrained-off CMSC payments.

2 *Analysis of Other Anomalous Events*

Anomalous events (market outcomes that fall outside predicted patterns and norms) do not necessarily result in high prices or large uplift payments, nor are they necessarily confined to a single hour or day. Since its May 2017 Monitoring Report, the Panel has expanded its analysis of anomalous events beyond those which meet or exceed pre-determined thresholds. Other criteria for assessing events include: the appropriateness of the market outcome relative to the Market Objective and the Market Rules;[38] the novelty and frequency of an unexpected event; and the relevance of the outcome to current IESO initiatives and stakeholder engagements. The Panel's approach is informed by the historic thresholds, as summarized in the preceding sections, but has been expanded to include other relevant events as appropriate.

In the section that follows, the Panel reports on an anomalous event during the Summer 2016 Period relating to a dispatchable load operating under constraints arising at its facility.

2.1 *Dispatchable Loads Operating under Operational Constraints*

Relevance

The Market Rules permit generators to request alternate dispatch instructions in situations where following the IESO's initial instructions would endanger the safety of any person, damage equipment or violate any applicable law (referred to as SEAL-related constraints). In such situations, generators are required to notify the IESO of their inability to follow dispatch instructions and to request that their dispatch be constrained to reflect their revised level of output.

While it is appropriate for generators to request that their dispatch be constrained to respect SEAL-related conditions at their facilities, it is inappropriate for them to receive CMSC payments as a result given that the constraint is necessitated by conditions at the facility rather than by conditions on the IESO-controlled grid. In December 2011, the IESO implemented a market rule amendment to allow the recovery of CMSC payments made to generators when they are unable to follow their initial dispatch instructions by reason of a SEAL-related constraint.

[38] Section 2 of Chapter 1 of the Market Rules states that the objective of the IESO-administered markets is to promote an efficient, competitive and reliable market for the wholesale sale and purchase of electricity and ancillary services in Ontario.

While provisions exist to recover CMSC payments made under SEAL-related constraints for generators, the same is not true for such payments when made to dispatchable loads. The Panel sees no reason why this outcome would be appropriate, as the root cause of the payments is the same in both cases. In the following section the Panel highlights one example of a dispatchable load receiving CMSC payments associated with a constraint necessitated by conditions at the facility, similar to a SEAL-related constraint.

Analysis

In HE 19 on August 10, 2016, a dispatchable load informed the IESO that it could not follow its expected dispatch due to issues at its facility. The IESO placed a manual constraint of 0 MW from HE 20 to HE 22 to reflect expected consumption by the load. This resulted in over $360,000 in constrained-off CMSC payments, as the load's original bids at $1,999/MWh were still in effect.

The conditions at the dispatchable load that necessitated the operational constraint in this case may not fall into the SEAL categories specified in the Market Rules that currently apply to generators. Nonetheless, it is a clear example of a dispatchable load receiving CMSC payments due to an operational constraint specific to its facility, and in this regard it is similar to a SEAL-related constraint. In the Panel's view, it is inappropriate that dispatchable loads are compensated for SEAL-related and other operational constraints arising from conditions at their facilities. The IESO should also examine whether the scope of the current provisions that allow it to recover CMSC payments from generators in relation to SEAL-related constraints should be expanded to cover any other operational constraints arising from conditions at the generator's facility.

Recommendation 3-1:

The Independent Electricity System Operator should implement rules that allow it to recover Congestion Management Settlement Credit payments made to dispatchable loads when those payments are the result of an operational constraint arising from conditions at the dispatchable load's facility. The IESO should also examine whether the scope of the current provisions that allow it to recover CMSC payments from generators in relation to SEAL-related constraints should be expanded to cover any other operational constraints arising from conditions at the generator's facility.

Chapter 4: Matters to Report in the Ontario Electricity Marketplace

1 *Introduction*

In this chapter, the Panel discusses potential market design deficiencies or concerns related to market participant conduct or activities of the IESO that are not necessarily linked to events during the May 1, 2016 – October 31, 2016 reporting period.

2 *New Matters*

2.1 *Constrained-on CMSC for Exporters*

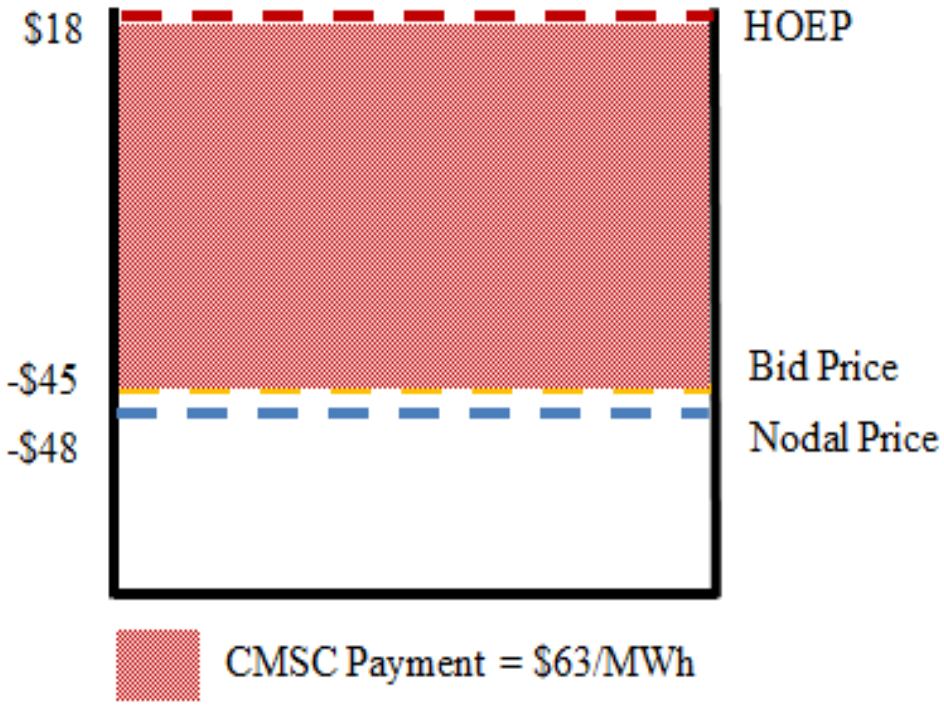
In its January 2010 Monitoring Report, the Panel identified that exporters may use strategic bids to obtain significant Congestion Management Settlement Credit (CMSC) payments during periods of excess local supply. Periods of excess local supply are particularly prevalent in the Northwest, a chronically congested region due to abundant hydroelectric generation, low demand and relatively limited transmission capacity linking it to other load centres in Ontario. Such transmission constraints cause a divergence between the Hourly Ontario Energy Price (HOEP) and local nodal prices; this is evident in the Summer 2016 Period when the average hourly nodal price in the Northwest was -$48/MWh, while the average HOEP was $18/MWh. Notionally, a -$48/MWh price implies that all suppliers scheduled at that price were willing to pay $48/MWh or more to supply energy.[39] Of course, a -$48/MWh average price over a six month period is not reflective of the underlying economics of supply in the region. In other words, suppliers to the Northwest did not actually have to pay this amount to deliver energy; instead, they were paid the HOEP, or roughly $18/MWh on average. The disconnect between the average nodal price and the HOEP is just one consequence of Ontario's two-schedule system.

When scheduling exports, the IESO's dispatch tool treats the -$48/MWh average nodal price as though it reflects underlying economics. As illustrated in Figure 4-1, this provides exporters with an opportunity to receive constrained-on CMSC payments on the basis of the spread between their bid price and the HOEP. To be constrained on, the exporter's bid price must be higher than the nodal price but lower than the HOEP. Since the bid is economic in the constrained sequence (which had an average nodal price of -$48/MWh) but uneconomic in the unconstrained sequence

[39] This also implies that all exporters scheduled at that price were willing to be paid that price or more to take power from the Northwest and deliver it to neighbouring jurisdictions.

(which had an average HOEP of $18/MWh), the export is constrained-on. The greater the spread between the exporter's bid price and the HOEP, the higher the constrained-on CMSC payment.

Figure 4-1: Illustration of Constrained-on CMSC Calculation



The opportunity to receive significant CMSC payments gives exporters the incentive to engage in a behaviour that the Panel has previously described as "nodal price chasing", which involves submitting bids as close to the nodal price as possible without going below in order to maximize CMSC payments. To eliminate this incentive and limit the resulting uplift charges, the Panel previously recommended that the IESO use a replacement bid price of $0/MWh when calculating the CMSC payable for negatively-bid exports.[40]

In response to the Panel's recommendation, the IESO agreed that, for CMSC calculation purposes, a replacement bid price was warranted. However, the IESO was concerned that setting the replacement bid price too high might discourage otherwise efficient trades at negative prices,

[40] For more information, refer to Chapter 3, pg. 97-104 of the Panel January 2010 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/msp_report_201001.pdf

and it therefore set the replacement bid price at -$125/MWh. The IESO's rationale for a negative non-zero replacement bid price was to minimize the potential loss of efficient export transactions that may occur between jurisdictions with negative prices.

An efficient transaction moves power from a lower-price to a higher-price jurisdiction; accordingly, an efficient export transaction from Ontario involves buying power from Ontario at a lower price and selling that power to another jurisdiction at a higher price. The same applies for negatively priced transactions; for example, an export would be considered efficient if the Midcontinent Independent System Operator (MISO) price in Minnesota was -$110/MWh and the Ontario nodal price at the intertie was -$120/MWh. Under such circumstances an exporter would be paid $120/MWh to buy power in Ontario, but pay $110/MWh to sell it in Minnesota, for a profit of $10/MWh. The IESO worried that if it set the replacement bid price too high, such as a price of -$100/MWh, then this otherwise efficient transaction would not be pursued because it was no longer profitable.

To assess the efficiency implications of a replacement bid price on electricity trading between neighbouring jurisdictions and the Northwest region of Ontario, the IESO considered differences between nodal prices in the Northwest and the locational marginal price in Minnesota.[41] The IESO decided that a replacement bid price should limit the opportunity for efficient transactions in no more than 1% of the hours when the MISO price in Minnesota was negative and greater than the nodal price in the Northwest of Ontario. The IESO calculated that this criterion corresponded to a replacement bid price of -$125/MWh.[42]

The Panel believes that this efficiency argument was ill-founded because it did not account for the fact that the nodal prices in the Northwest are artificially low and do not reflect the actual cost of supplying power in the region, thus undermining the premise that a -$125/MWh replacement price supports efficient transactions.

[41] The IESO's assessment – and the Panel's assessment that follows – is limited to exports on the Minnesota intertie. The assessments are limited to Minnesota because the Northwest is the only zone in Ontario that regularly experiences negative nodal prices.
[42] The methodology consisted of identifying the 1st percentile in the subset of hours when the MISO external price was negative and greater than the Ontario nodal price, which resulted in a price of -$120/MWh. After considering transactional costs in Ontario (including relevant hourly and monthly uplifts as well as an export tariff fee) and transactional costs in MISO (including the revenue sufficiency guarantee), the IESO modified the applicable price to be -$125/MWh.

Further analysis into MISO's Minnesota prices indicates that by changing the replacement bid price to $0/MWh, the loss of any supposedly efficient export transactions would be insignificant. It should be emphasized that the transactions would be truly "efficient" only if the negative nodal price in Ontario during the hours in question accurately reflects the underlying cost of supply, which at least on average is clearly not the case.

Table 4-1 displays a price frequency profile for all hours from July 2011 to September 2016. It describes:

1. Applicable price range for MISO's real-time locational marginal prices (LMP) at the Minnesota intertie. For example, the first range denotes the set of hours when the MISO real-time LMP was greater than -$2,000/MWh but less than or equal to -$125/MWh.
2. Number of hours when the MISO real-time LMP is in the specified price range, all of which total 46,032 hours during the Panel's study period.
3. Number of hours when the MISO real-time LMP exceeded the Ontario nodal price; this represents the number of hours where potentially efficient transactions could have occurred in each price range.
4. Number of hours when the MISO real-time LMP exceeded the Ontario nodal price and where exports actually flowed; this represents the number of hours where efficient transactions actually occurred in each price range.

Table 4-1: Frequency Profile of Locational Marginal Prices at Minnesota Intertie
July 2011 – September 2016
(Number of Hours)

MISO Real-Time Locational Marginal Price Range ($/MWh)	Number of Hours	Number of Hours when the MISO Price Exceeded the Ontario Nodal Price	Number of Hours when the MISO Price Exceeded the Ontario Nodal Price and Exports Flowed
-2000 to -125	16	2	1
-124.9 to 0	568	110	28
0.1 to 100	44,891	38,975	12,865
100.1 to 200	442	437	156
200.1 to 1000	114	115	42
1000.1 to 2000	1	1	1
Total	46,032	39,640	13,093

It is noteworthy that only 112 hours (approximately 0.25% of all hours, as shown in the top two rows of the middle column of Table 4-1) even had the potential to support an efficient transaction when the MISO real-time LMP was less than or equal to $0/MWh. During those few

hours when an efficient transaction was theoretically possible, an efficient export transaction only occurred in 29 of those hours (approximately 0.065% of all hours, as shown in the top two rows of the right-hand column of Table 4-1). This suggests that increasing the replacement bid price for negatively-bid exports to $0/MWh would have virtually no impact on efficiency. However, implementing a $0/MWh replacement bid price would have reduced consumer uplift charges by over $2.1 million from July 2011 to September 2016.

In reassessing the appropriate replacement bid price, the IESO may wish to consider the transaction costs associated with exporting, such as uplift, the export tariff and charges associated with importing into other jurisdictions. These costs effectively add to the replacement bid price floor, so to avoid setting a replacement bid price that is effectively above $0/MWh, the IESO may wish to consider setting a slightly negative replacement bid price.

Recommendation 4-1:

The Independent Electricity System Operator should set the replacement bid price to $0/MWh, or slightly negative, when it calculates constrained-on Congestion Management Settlement Credit payments for exports bid at negative prices.

2.2 *Claw Back for Failure to Provide Operating Reserve when Activated*

Operating reserve (OR) is standby capacity intended to respond to, and recover from, a contingency on the grid. Such a contingency could take the form of a sudden, unexpected increase in demand, a forced outage to generation or transmission equipment, or significant dispatch deviations by generators or dispatchable loads, among other possibilities. OR requirements must adhere to reliability standards established by the North American Electric Reliability Council and the Northeast Power Coordinating Council.[43] This usually amounts to an OR requirement of approximately 1,500 MW in any given hour. Resources scheduled to provide standby capacity in the 10-minute OR market must provide the entirety of that energy within 10 minutes of receiving an OR activation, and must be able to provide the activated energy for at least one hour; likewise for 30 minute OR.[44]

[43] The quantity of OR scheduled in a given hour must equal the largest possible single contingency plus half of the second largest possible contingency.
[44] Refer to the Market Rules, Chapter 5 Appendices, Section 1.2

To encourage compliance with OR activations, the Market Rules make provision for a claw back of OR payments from market participants that fail to meet their OR activations.[45] The claw back is a partial or full recovery of OR payments[46] received during the 30 days prior to the failed OR activation.[47] The claw back is assessed for each metering interval during the OR activation in which the market participant failed to deliver the required energy. The portion of payments clawed back is equal to the portion of the total scheduled energy that the market participant did not provide upon activation –this value is referred to as the energy shortfall fraction. For example, if a market participant provides the entirety of its scheduled energy, none of its OR payments would be clawed back; if it fails to provide 20% of its scheduled energy, then the claw back would be 20% of its OR payments. As this assessment is to be carried out for each metering interval during the OR activation, the total claw back could exceed the OR payments initially earned in the 30 days prior to the failed OR activation.[48] The claw back process involves a manual settlement adjustment by the IESO. The Market Rules require the IESO Board of Directors to set a materiality threshold, being the energy shortfall fraction below which no OR payments would be clawed back.

Despite the rule for this claw back being in place since market opening, it has never been applied. Prior to June 2016, the IESO Board of Directors had not set the materiality threshold to establish when claw backs should occur. In June 2016, the IESO set the materiality threshold to a value of infinity,[49] meaning that even if a market participant were to completely ignore an OR activation, the IESO would not claw back any OR payments under this rule.

[45] Refer to the Market Rules, Chapter 9, Section 3.8
[46] OR payments consist of OR market settlement credits and OR CMSC. OR market settlement credits are payments for a market participant's standby schedule. If a market participant has an OR standby schedule of 100 MW in the 10-minute OR market, it is paid the 10-minute OR market clearing price for those 100 MW, regardless of whether the OR was activated. OR CMSC is analogous to energy market CMSC in that a resource can be constrained on or constrained off relative to its unconstrained OR schedule, receiving OR CMSC to return it to the operating profit implied by its unconstrained OR schedule.
[47] The Market Design Committee deemed that a "billing period" would be an appropriate time horizon over which to evaluate any claw back for a market participant's non-compliance. Such a claw back necessarily had to be large in order to incentivize a market participant to follow its OR activation at all times. In practical terms, a "billing period" would amount to a settlement month lasting 30 days or 720 hours.
[48] For example, suppose a market participant completely ignored its OR activation during two metering intervals. If the market participant earned $10,000 in OR payments in the 30 days prior to this failed OR activation, the OR claw back would amount to $20,000.
[49] Refer to the equations published for charge types 251, 253, and 255 in the *IESO Charge Types and Equations* manual: http://www.ieso.ca/sector-participants/market-operations/-/media/490945b625004c60b45982771a644356.ashx

From January 2012 to October 2016, market participants in the 10-minute OR markets received 3,800 individual OR activations, yet failed to fully respond to their OR activations in over 1,700 of those instances. Had the materiality threshold for a permissible energy shortfall fraction been set to 0, the Panel estimates that there would have been over $6 million in OR claw backs. The Panel believes that an inoperative claw back provision is inappropriate, particularly where market participants are able to retain significant payments for services they did not provide. Moreover, an infinity materiality threshold can reduce the incentive to provide OR when called upon. The Panel is therefore recommending that the materiality threshold value be revised such that operating reserve payments are clawed back when a market participant fails to fully respond to its operating reserve activation. In the Panel's view, a materiality threshold higher than 0 would appear to be warranted only if the claw back is a manual process, to accommodate situations where the level of effort involved in administering the claw back would be disproportionate to the benefit.

Recommendation 4-2A:

The Independent Electricity System Operator's Board of Directors should revise the materiality threshold value such that operating reserve payments are clawed back when a market participant fails to fully respond to its operating reserve activation.

Calculating the Claw Back

The Panel has also identified what it believes to be a flaw in the formula for establishing the claw back amount.

In the Panel's view, since the claw back is intended to address the failure to respond fully to an OR activation, the amount of the claw back should be calculated based on the energy shortfall relative to the OR activation quantity, not the total scheduled quantity (which includes energy that was scheduled prior to the activation). The existing formula utilises the latter methodology,[50] making the claw back highly dependent on the facility's operating state prior to activation, not the extent to which it responded to the OR activation.

[50] Refer to the Market Rules, Chapter 9 Section 3.8.2.1

For example, suppose there are two generators, Generator A and Generator B, both of which are activated to provide 10 MW of OR. Assume Generator A was initially providing 0 MW and its activation required it to increase to 10 MW, while Generator B was producing 100 MW of energy before it was activated to increase to 110 MW. When the generators receive their respective OR activations, both ignore the activation entirely. Under the claw back formula as currently written, and absent the materiality threshold of infinity, the claw back for Generator A would be calculated at 100% (MW Shortfall / Total Energy Schedule, 10 MW / 10 MW = 100%) of any applicable OR payments, while the claw back for Generator B would only be 9.09% (10 MW / 110 MW = 9.09%). Both generators equally failed to respond to their OR activation; however, Generator B would be treated more favourably by reason of already generating energy when the OR activation occurred. Intuitively this is neither equitable nor commensurate with the purpose that the claw back is intended to serve. Where a facility fails to provide OR when activated, it would be more appropriate to calculate its claw back as a function of the energy delivered in response to the OR activation, as opposed to the total energy delivered. The Panel believes that the IESO should calculate the claw back on this basis.

Recommendation 4-2B:

When a market participant fails to fully respond to an operating reserve activation, the Independent Electricity System Operator should calculate the claw back based on the ratio of the energy not provided in response to the activation relative to the energy required by the activation.

NEXUS ENERGY INC.	-and-	INDEPENDENT ELECTRICITY SYSTEM OPERATOR (IESO)
Applicant		Respondent

IN THE MATTER OF an Arbitration under Chapter 3 of the IESO Market Rules made pursuant to section 32 of the Ontario *Electricity Act, 1998*, S.O. 1998, c. 15, as amended

AFFIDAVIT OF FRANCOIS TARDIF
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TAB 4

IN THE MATTER OF an Arbitration under Chapter 3 of the IESO Market Rules made pursuant to section 32 of the Ontario *Electricity Act, 1998*, S.O. 1998, c. 15, as amended

B E T W E E N:

NEXUS ENERGY INC.

Applicant

- and -

INDEPENDENT ELECTRICITY SYSTEM OPERATOR (IESO)

Respondent

AFFIDAVIT OF GIUSEPPE ROSATI

AFFIRMED OCTOBER 30, 2025

I, Giuseppe Rosati, of the City of Toronto, in the Province of Ontario, AFFIRM:

1. I was employed by Ontario Power Generation ("**OPG**") for eighteen years. During my time at OPG I held various roles, including Senior Manager, Market Operations and Senior Manager, and Market Compliance. I have knowledge of the matters contained in this affidavit unless otherwise specified.

ROLE AND DUTIES IN MARKET OPERATIONS

2. In my role in Market Operations, I was involved in the day-to-day physical trading operations of OPG, and during my time in OPG's Market Compliance team, I was involved in ensuring the organization's compliance with IESO market rules.

INTERIE ENERGY TRADING

3. At no time during my career at OPG was I aware – nor, to my knowledge, were my colleagues aware – that the IESO could or would seek to recover intertie congestion price, or "**ICP**", in respect of failed intertie transactions.

4. I was also not aware the IESO would treat intertie transaction failures as a compliance issue (unless it involved particularly blameworthy conduct), other than recovering payments actually made to and received by the energy trader market participant such as transmission rights ("**TR**") payments or congestion management settlement credits ("**CMSC**").

5. For almost the entirety of my career, import failure charges ("**IFCs**") and export failure charges ("**EFCs**") were seen to be the primary financial consequence of a failed intertie transaction. While I was aware that the OEB's Market Surveillance Panel had recommended changes to how the IESO calculated IFCs and EFCs, I was unaware of any action taken by the IESO in that regard until the IESO's Market Renewal Program was implemented in May 2025.

IESO'S SANCTION SUMMARIES

6. I have read the summary of MACD's compliance investigation of Nexus Energy Inc. on the IESO's "Sanctions" public webpage, as well as the summaries pertaining to investigations of other market participants such as Citigroup and MAG Energy Solutions pertaining to failed intertie transactions on the IESO's "Negotiated Settlements" webpage. Printouts of those summaries are attached together to this affidavit as **Exhibit "A"**.

7. These summaries lack detail of the circumstances surrounding the failed intertie transactions and of how the sanctions or negotiated settlements have been calculated or what exactly they are comprised of. The inferences I drew when I read those summaries were that those cases involved the receipt of TR payments or other revenues received by the market participants like CMSC, or otherwise involved particularly blameworthy conduct.

AFFIRMED BEFORE ME by Giuseppe Rosati, in the City of Toronto, in the Province of Ontario before me at the City of Toronto, in the Province of Ontario on October 30, 2025 in accordance with O. Reg 431/20, Administering Oath or Declaration Remotely.

Commissioner for Taking Affidavits
(or as may be)

Giuseppe Rosati

October 30, 2025

Keith Edward Hickey, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.

Expires June 24, 2027.

Exhibit "A"

IESO "Sanctions" webpage and IESO "Negotiated Settlements" webpage

Exhibit "A"

to the Affidavit of Giuseppe Rosati

Sworn before me on October 30 , 2025 in accordance with O. Reg. 431/20, Administering Oath or Declaration Remotely



Commissioner for Taking Affidavits
(*or as may be*)

October 30, 2025

Keith Edward Hickey, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.

Expires June 24, 2027.

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Compliance Enforcement

MACD enforces compliance through the detection and investigation of potential breaches of the market rules. The Vice President, MACD has the authority to issue non-compliance rulings and impose sanctions, including financial penalties, when the rules have been breached. MACD also administers other rules which may result in repayments to the market.

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Negotiated Settlements

Suspension or Termination Orders

Sanctions

Market participants who are found in breach of the market rules or reliability standards may be subject to enforcement sanctions if MACD considers it appropriate. Such possible enforcement sanctions range from non-compliance letters to financial penalties. Persistent breaches may result in de-registration, suspension or termination of the right to participate in the market.

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A key goal of enforcement is to encourage compliance which benefits the reliability of the IESO-controlled grid and operations of the IESO-administered markets. In considering the appropriate financial penalty in cases where a penalty is the chosen sanction, Chapter 3, section 6.2.7 of the market rules requires MACD to consider a range of factors such as: actual or potential impacts on the market, other participants and reliability; “the presence and quality” of the market participant’s compliance program; and other factors. Market participants who have developed effective Internal Compliance Programs (ICPs) reduce the likelihood of committing breaches and being subject to enforcement actions.

Below is a list of enforcement sanctions that have been applied by MACD.

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Show 10 entries

Date of Sanction	Market Participant	Description
2020	Citigroup Energy Canada ULC	On December 16, 2020, pursuant to Chapter 3 of the market rules, the IESO issued to CECU a non-compliance letter and ordered the adjustment of settlement amounts to recover from CECU a total of $378,254 for breaches of Chapter 7, section 7.5.8A of the market rules. During the period from January 4, 2012 to January 7, 2018, CECU failed to schedule some promised import and/or export energy at the Michigan-Ontario, Minnesota-Ontario and New York-Ontario borders. When a market participant fails to schedule cross-border energy other than for bona fide and legitimate reasons, they may avoid paying certain settlement amounts and/or may receive unwarranted payments. Failed cross-border trades cause adverse impacts in the IESO-administered markets. For example, avoided payments can result in settlement shortfalls and, in turn, higher costs to consumers. The market rules provide for the adjustment of settlement amounts, including the recovery of avoided settlement amounts and payments received due to cross-border trade failures that are within a market participant's control.

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Compliance Enforcement

MACD enforces compliance through the detection and investigation of potential breaches of the market rules. The Vice President, MACD has the authority to issue non-compliance rulings and impose sanctions, including financial penalties, when the rules have been breached. MACD also administers other rules which may result in repayments to the market.

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Negotiated Settlements

In some circumstances, MACD may enter into a voluntary negotiated settlement with a Market Participant, rather than issuing formal enforcement actions such as the imposition of a financial penalty. MACD's main objective is to secure the best possible outcomes for both reliability and the market, rather than the enforcement of the rules for its own sake. Accordingly, it may consider whether an alternative resolution, which typically includes a range of mitigation and/or remedial features, is preferable.

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Below is a list of negotiated settlements agreed upon by MACD.

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Date	Market Participant	Description of Settlement
2021	MAG Energy Solutions Inc.	The IESO has agreed to enter into a settlement with MAG Energy Solutions Inc. (“MAGES”) regarding certain trading activities on the New York-Ontario, Manitoba-Ontario, Michigan-Ontario, Minnesota-Ontario and Quebec-Ontario interties during the period from June 2006 to July 2020. As a result of an investigation, the IESO issued a notice of non-compliance pursuant to Chapter 3 of the Market Rules notifying MAGES that, among other things, the IESO had determined that MAGES failed to schedule certain intertie transactions contrary to Chapter 7, section 7.5.8A of the Market Rules. When a market participant fails to schedule cross-border energy, it may not be charged certain settlement amounts and/or may receive unwarranted payments. The Market Rules provide for the adjustment of settlement amounts, including the recovery of settlement amounts avoided and payments received due to cross-border trade failures that are within a market participant’s control. Without acknowledging or admitting any breach or violation of the Market Rules, MAGES has agreed to voluntarily pay to the IESO the amount of $1.274 million to resolve this matter.

Date	Market Participant	Description of Settlement

Date	Market Participant	Description of Settlement
2021	Rayonier A.M. Canada Enterprises Inc. (formerly Tembec Enterprises Inc) and Rayonier A.M Canada G.P (formerly Tembec General Partnership) (collectively RYAM)	The IESO has entered into a settlement agreement with Rayonier A.M. Canada Enterprises Inc. (formerly Tembec Enterprises Inc.) and Rayonier A.M Canada G.P (formerly Tembec General Partnership), collectively “RYAM”, in relation to matters previously under investigation. Pursuant to Chapter 3, section 6.2.7 of the Market Rules, the IESO has issued a financial penalty and non-compliance letter to RYAM, based upon the breach determinations set out below. While RYAM does not acknowledge or admit to any violation of the Market Rules, for the purposes of the settlement, RYAM does not contest the IESO's determinations of breaches of the following Market Rules: • Chapter 1, section 11.2.1; • Chapter 3, section 6.2.6; • Chapter 5, section 3.5.1.2; • Chapter 7, section 2.1.2.3; • Chapter 7, section 3.3A.11; • Chapter 7, section 3.3.8; • Chapter 7, section 3.5.6.2; • Chapter 7, section 3.5.6.3; • Chapter 7, section 7.4.2; • Chapter 7, section 7.5.1; and

Date	Market Participant	Description of Settlement
		• Chapter 7, section 7.5.2. RYAM has agreed to repay to the IESO the amount of $18,000,000 (Eighteen Million Dollars) in respect of congestion management settlement credit payments received during the period under investigation. RYAM has also agreed to operate the Spruce Falls facility as a non-dispatchable load for the next five years. Based upon the determinations of breach, the IESO has issued a financial penalty and non-compliance letter. The financial penalty requires RYAM to pay $1,000,000 (One Million Dollars) immediately. A remaining part of the penalty, totalling $3,400,000 (Three Million Four Hundred Thousand Dollars) is suspended, but will become payable should RYAM fail to meet its obligations under the settlement agreement. The IESO notes that while under investigation, when notified of certain issues, RYAM took some steps to improve its compliance with the Market Rules. However, the IESO has determined that RYAM breached Chapter 3, section 6.2.6, in relation to a failure to provide a timely and/or comprehensive response to a request for information.

Date	Market Participant	Description of Settlement
2019	Chubu TT Energy Management Inc.	On August 8, 2019, pursuant to Chapter 3, section 6.2.3 of the IESO market rules, the IESO issued a notice (“Notice”) to Chubu TT Energy Management Inc. (“Chubu”) regarding the alleged breach of Chapter 7, section 7.5.8A of the market rules. The Notice related to Chubu’s conduct in certain transactions in the IESO-administered markets between August 25, 2015 and June 16, 2018 over the Michigan-Ontario, Minnesota-Ontario and New York-Ontario interties (the “Subject Transactions”). Specifically, the Notice stated that the IESO is investigating whether Chubu failed to schedule the Subject Transactions other than for bona fide and legitimate reasons, contrary to Chapter 7, section 7.5.8A of the market rules. Without acknowledging or admitting any breach or violation of the market rules, Chubu has agreed to voluntarily pay to the IESO the amount of $650,000, in full and final satisfaction of the allegations in the Notice and the underlying investigation. The IESO has terminated the investigation.

NEXUS ENERGY INC.	-and-	INDEPENDENT ELECTRICITY SYSTEM OPERATOR (IESO)
Applicant		Respondent

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AFFIDAVIT OF GIUSEPPE ROSATI
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MEMORIAL OF THE APPLICANT,
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