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IESO Charge Types and Equations

Issue 5.0
November 17, 2025

This document enumerates the various *charge types* and equations used in the *IESO settlements process* for *IESO-administered markets*.

LST-84

Document Change History

Issue	Reason for Issue	Date
Refer to Issue 86.0 (IMP_LST_0001) for changes prior to Market Transition.		
1.0	Market Transition	November 11, 2024
2.0	Issued in advance of MRP Go Live – May 1, 2025	April 25, 2025
3.0	Updated in advance of Baseline 53.1	May 30, 2025
4.0	Updated for Baseline 54.0	September 10, 2025
5.0	Issued in advance of Baseline 54.1	November 17, 2025

Related Documents

Document ID	Document Title
MAN-116	Market Manual 5: Settlements, Part 5.5: IESO-Administered Markets Settlement Amounts
MAN-117	Market Manual 5: Settlements, Part 5.6: Non-Market Settlement Programs

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Reference (Section and Paragraph)	Description of Change
Section 2.2	Modified charge type 1319 – Capacity Obligation – Buy-Out Charge as part of 2025 enhancements to the capacity auction

Market Transition

A.1.1   This *market manual* is part of the *renewed market rules,* which pertain to:

    A.1.1.1   the period prior to a *market transition* insofar as the provisions are relevant and applicable to the rights and obligations of the *IESO* and *market participants* relating to preparation for participation in the *IESO administered markets* following commencement of *market transition;* and

    A.1.1.2   the period following commencement of *market transition* in respect of all the rights and obligations of the *IESO* and *market participants.*

A.1.2   All references herein to chapters or provisions of the *market rules* or *market manuals* will be interpreted as, and deemed to be references to chapters and provisions of the *renewed market rules.*

A.1.3   Upon commencement of the *market transition*, the *legacy market rules* will be immediately revoked and only the *renewed market rules* will remain in force.

A.1.4   For certainty, the revocation of the *legacy market rules* upon commencement of *market transition* does not:

    A.1.4.1   affect the previous operation of any *market rule* or *market manual* in effect prior to the *market transition*;

    A.1.4.2   affect any right, privilege, obligation or liability that came into existence under the *market rules* or *market manuals* in effect prior to the *market transition*;

    A.1.4.3   affect any breach, non-compliance, offense or violation committed under or relating to the *market rules* or *market manuals* in effect prior to the *market transition*, or any sanction or penalty incurred in connection with such breach, non-compliance, offense or violation

    A.1.4.4   affect an investigation, proceeding or remedy in respect of:

        (a)   a right, privilege, obligation or liability described in subsection A.1.4.2; or

        (b)   a sanction or penalty described in subsection A.1.4.3.

A.1.5   An investigation, proceeding or remedy pertaining to any matter described in subsection A.1.4.3 may be commenced, continued or enforced, and any sanction or penalty may be imposed, as if the *legacy market rules* had not been revoked.

Market Manual Conventions

The standard conventions for *market manuals* are as follows:

- The word 'shall' denotes a mandatory requirement;

- References to *market rule* sections and sub-sections may be abbreviated in accordance with the following representative format: '**MR Ch.1 ss.1.1-1.2'** (i.e. *market rules,* Ch.1, sections 1.1 to 1.2);

- References to *market manual* sections and sub-sections may be abbreviated in accordance with the following representative format: '**MM 1.5 ss.1.1-1.2'** (i.e. *market manual* 1.5, sections 1.1 to 1.2);

- Internal references to sections and sub-sections within this manual take the representative format: 'sections 1.1 – 1.2';

- Terms and acronyms used in this *market manual* in its appended documents that are italicized have the meanings ascribed thereto in **MR Ch.11**;

- All user interface labels and options that appear on the *IESO* gateway and tools are formatted with the bold font style; and

- Data fields are identified in all capitals.

Unless otherwise noted, usage of variable subscripts and superscripts within this document shall mirror the same usage within **MR Ch.9**. One notable exception is the usage of notation to sum across *settlement amounts* for *charge type* "c". This is noted within the applicable equations.

– End of Section –

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.

This document must be read in conjunction with the applicable *market rules*. Where there is a conflict between this document and the *market rules*, the *market rules* shall prevail.

1.2.   Scope

This document provides the formulas and the Harmonized Sales Tax (HST) tax treatment for each *charge type* implemented in the *IESO settlements* system. 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, refer to the Format Specifications for Settlement Statement Files and Data Files document located on the Technical Interfaces webpage under 'Commercial Reconciliation'.

This document is structured as follows:

Section 2**:** Active *IESO* Charge Types and Equations

Section 2.1**:** This section contains a description of the variables that are specific to *charge types* associated with *applicable law* within section 2.2. Variables not defined in this section are as defined in **MR Ch.9 Appendix 9.2** or within the relevant *market rule* that is specific to the *charge type*.

Section 2.2: This section contains all active *IESO charge types* and equations that are either:

- part of the *IESO-administered market*, or

- associated with non-market *settlement* programs as mandated by *applicable law*, administered by the *IESO*.

Section 2.3: This section contains a description of rounding conventions for *charge type* calculations within section 2.2.

Section 2.4: This section contains 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 uplifts*.

Section 3: Inactive *IESO* Charge Types and Equations

Similar to subsections within section 2, however the provisions of section 3 are applicable to those *IESO charge types* and equations that are no longer active and have been retained in the event that a re-calculation of the *charge type* is required. The *charge types* included in this section are:

- expired (i.e. program has ended);

- replaced with another *charge type*;

- replaced with an updated calculation (i.e. due to new variable or exclusion/addition of *charge type* to be uplifted); or

- retired under the Market Renewal Program (MRP), effective on the commencement of *market transition*.

This section also includes section 3.6 which 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) which has been retired under MRP.

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.   Contact Information

Changes to this document are managed via the *IESO* Change Management process. Stakeholders are encouraged to participate in the evolution of this document via this process.

As part of the authorization and registration process[1], *market participants* are required to identify a Settlements Contact. If a *market participant* has not identified a specific contact, the *IESO* will seek to contact the Primary Contact unless alternative arrangements have been established between the *IESO* and the *market participant*.

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[1] Refer to **MM 1.5** https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/imrm/MM-1-5-market-registration-procedures-20220909.ashxfor adding and updating contact roles with the *IESO*.

To contact the *IESO*, you can email *IESO* Customer Relations at customer.relations@ieso.ca or use telephone or mail. Telephone numbers and the mailing address can be found on the *IESO* website. *IESO* Customer Relations staff will respond as soon as possible.

If you have a specific inquiry regarding a *settlement amount* on any of your *settlement statements*, refer to **MM 5.10** for further details.

– End of Section –

2.   Active IESO Charge Types and Equations

The provisions of this section include all active *charge types* that are:

- part of the *IESO-administered market*; and

- associated with non-market *settlement* programs as mandated by *applicable law*, administered by the *IESO.*

2.1.   Variable Descriptions

The following Table 2-1 contains descriptions of variables that are specific to *charge types* associated with *applicable law* within section 2.2.

Variables not defined in this table are as defined in **MR Ch.9 Appendix 9.2** or within the relevant *market rule* that is specific to the *charge type*.

Table 2-1: Variable Descriptions for Active Charge Types and Equations

Key to the Table Below				
Variable used within Section 2	**Data Description**	**Description**	**Maximum Rounding Convention in Settlement Statements or Data Files[2]**	**Relevant Reference and Other Information**
EEQ	Excluded Energy Quantity	The total volume of *energy* (MWh) supplied to Fort Frances Power Corporation Distribution Inc. by Abitibi-Consolidated Inc. during the month.	3	Refer to regulations.
$EGEI_k$	Embedded Generator Energy Injection	The total volume of *energy* (MWh) supplied by *embedded generator*s during the month to *distributor*s who are *market participants* and to all embedded distributors to whom the *market participant* 'k' is the host *distributor*, adjusted for	3	Refer to regulations.

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[2] 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 Specifications for Settlement Statements and Data Files.

Variable used within Section 2	Data Description	Description	Maximum Rounding Convention in Settlement Statements or Data Files[2]	Relevant Reference and Other Information
		losses as required by the *OEB*, Retail Settlement Code.		
ETS	Export Transmission Service Tariff Rate	Export Transmission Service Tariff Rate in units of $/MWh.	2	Subject to the OEB "Ontario Transmission Rate Order".
$GA\_AQEW_{g,k,h,M}{}^{m,t}$	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.		Refer to regulations.
GAR_B	Global Adjustment Rate for Class B	GA Class B Rate.		Refer to regulations.
GRP	Generator Regulated Price	A regulated price ($/MWh) with respect to output of OPG's regulated generating stations, set by the *OEB.*	2	Subject to regulation by the *Ontario Energy Board*.
$LCD_{k,h}{}^{m}$	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.	3	Subject to the OEB "Ontario Transmission Rate Order".
$NSD_{k,h}{}^{m}$	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*.	3	Subject to the OEB "Ontario Transmission Rate Order".

		Key to the Table Below		
Variable used within Section 2	**Data Description**	**Description**	**Maximum Rounding Convention in Settlement Statements or Data Files[2]**	**Relevant Reference and Other Information**
		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.		
$PDF_{k,m,d}$	Peak Demand Factor	The Peak Demand Factor for Class A Market Participant or Distributor 'k' for month 'm' with effectiveness ratio 'd'.		Subject to regulation by the *Ontario Energy Board*.
$PGS_{h,M}$	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'.		
PTS-L	Provincial Transmission Service Line Connection Service Rate ($/KW)	Line Connection Transmission Tariff Service Rate in units of dollars per kilowatt.	2	Subject to the OEB "Ontario Transmission Rate Order".
PTS-N	Provincial Transmission Service Network Service Rate ($/KW)	Network Transmission Tariff Service Rate in units of dollars per kilowatt.	2	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.	2	Subject to the OEB "Ontario Transmission Rate Order".
RPP_l	Regulated Price Plan	A fixed *energy* rate for all *metering intervals* based on consumption level l.		Subject to regulation by the *Ontario Energy Board*.

Variable used within Section 2	Data Description	Description	Maximum Rounding Convention in Settlement Statements or Data Files[2]	Relevant Reference and Other Information
$TCD_{k,h}{}^m$	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.	3	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*.		Subject to regulation by the *Ontario Energy Board*.
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 used within the documentation to describe the unique per MW or per MWh rate applied to specific quantities in order to calculate various *settlement amounts*.
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'.		Refer to regulations.

Key to the Table Below

2.2. Charge Types and Equations

The following tables contain all active *IESO charge types* and equations that are:

- part of the *IESO-administered market*; and
- associated with non-market *settlement* programs as mandated by *applicable law*, administered by the *IESO*.

Refer to section 3.2 for inactive *IESO charge types* and equations.

The following Table 2-2 provides a description of each of the column references for *charge types* and equations.

Table 2-2: Description of Column References for Charge Types and Equations

Key to the Table Below	
Charge Type Number	The designation number for each *charge type* enumerated below – which corresponds to the *charge type* numbers used on *settlement statements* and *invoices*.
Charge Type Name	The name of the *charge type*, including, where applicable, the abbreviated name used to describe the *settlement amount* within the *IESO market rules* and *market manuals*.
Market Rules Reference	The relevant reference to the variable in question within the *IESO market rules*.
Equation	The equation used by the *IESO settlements process* to calculate the *settlement amount* for the *charge type*.
Settlement Resolution	The level of granularity by which the *IESO settlements process* calculates the *settlement amount* for the *charge type*, and provides the supporting data in the *settlement* data file. Where: • Interval calculations are performed on the basis of each relevant, 5-minute *metering interval*, which when a charge type is defined at the hourly level can be determined by dividing by 12; • Hourly calculations are performed on the basis of each *settlement hour*; • Daily calculations are performed on the basis of each calendar day; • Monthly calculations are performed on the basis of a calendar month (equivalent to an *energy market billing period*); • Quarterly calculations are performed on the basis of 3 month intervals; • Yearly 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 the *charge type* 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 "Settlement 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.
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.
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.
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.
Comments	This column notes any *charge types* that are governed by various documentation other than the *IESO market rules* such as *applicable law.* References to other *market manuals* may be included here, where applicable.

2.2.1. Financial Market Charge Types and Equations

The following Table 2-3 describes the *charge types* and equations in the financial market.

Table 2-3: Financial Market Charge Types and Equations

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
52	Transmission Rights Auction Settlement Debit	MR Ch.8 s.3.17	$QTR_{k,h}{}^{i,j} \times TRMP$ Where 'TRMP' is the price of each *transmission right* in a single round of a *TR auction* and expressed in up to 2 decimal places.	Daily	Due *IESO*	Exempt	Exempt	Exempt	Exempt	

2.2.2. Physical Market Charge Types and Equations

The following Table 2-4 describes the *charge types* and equations in the *physical market*.

Table 2-4: Physical Market Charge Types and Equations

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
102	TR Clearing Account Credit (TRCAC)	MR Ch.9 s.4.9	**For loads:** $TRCAC_k = TRCAD_L \times \sum_H{}^{M,T} [(AQEW_{k,h}{}^{m,t}) / \sum_{K,H}{}^{M,T} (AQEW_{k,h}{}^{m,t})]$ **For exporters:** $TRCAC_k = TRCAD_E \times \sum_H{}^{L,T} [(SQEW_{k,h}{}^{i,t}) / \sum_{K,H}{}^{L,T} (SQEW_{k,h}{}^{i,t})]$	Monthly (when applicable)	Due MP	13	N/A	0	13	The *billing period* is defined in MM5.5: IESO-Administered Markets

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			Where: a. $TRCAD_L = (\sum_K TD_C / \sum_K TD_{C,C1}) \times TRCAD$ b. $TRCAD_E = (\sum_K TD_{C1} / \sum_K TD_{C,C1}) \times TRCAD$ c. TRCAD = the total dollar value (in \$ and up to 2 decimal places) of all disbursements from the *TR clearing account* authorized by the *IESO Board* in the current *energy market billing period*; d. C = the set of all monthly service *charge types* 'c' as follows: 650,651,652; e. C1 = the set of all monthly export transmission *charge types* 'c' as follows: 653; f. H = the set of all *settlement hours* 'h' in the *energy market billing periods* immediately preceding the current *energy market billing period*, as determined by *IESO Board*; g. T = the set of all *metering intervals* 't' in the *energy market billing periods* immediately preceding the current *energy market billing period*, as determined by the *IESO Board*; h. M = the set of all *registered wholesale meters* '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. I = the set of all *intertie metering points* 'i' during *energy market billing periods* immediately preceding the current *energy market billing period*, as determined by the *IESO Board*; and j. 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*.							Settlement Amounts, section 2.22.1
104 MRP updated	Transmission Rights Settlement Credit (TRSC)	MR Ch.9 s.3.8.1	****The following is effective on the commencement of *market transition*. Refer to section 3 for the version in effect prior to the commencement of *market transition*.**** 1. If the injection TR zone of the *transmission right* is in the *IESO control area*: $$TRSC_{k,h} = Max\left[0, QTR_{k,h}^{iz,jz} \times DAM\_PEC_h^{iz}\right]$$	Hourly	Due MP	0	0	0	0	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			2. If the withdrawal TR zone of the *transmission right* is in the *IESO control area*: $$TRSC_{k,h} = Max\left[0, -1 \times QTR_{k,h}^{iz,jz} \times DAM\_PEC_{h}^{jz}\right]$$ **Where:** a. $DAM\_PEC_{h}^{iz}$ = the *day-ahead market* external congestion price for *energy* in injection *TR zone* 'iz' in *settlement hour* 'h'; and b. $DAM\_PEC_{h}^{jz}$ = the *day-ahead market* external congestion price for *energy* in withdrawal *TR zone* 'jz' in *settlement hour* 'h'.						
114	Outage Cancellation/ Deferral Settlement Credit	MR Ch.9 s.4.14.12 and MR Ch.5 s.6.7.4	Manual Entry as per MR Ch.5 s.6.7.4.	Monthly	Due MP	13	N/A	N/A	N/A	
115	Unrecoverable Testing Costs Credit	MR Ch.9 s.4.14.12 and MR Ch.4 s.5.3.4	Manual Entry as per MR Ch.4 s.5.3.4.	Monthly	Due MP	13	13	13	13	
116	Tieline Maintenance Reliability Credit	MR Ch.9 s.4.14.12 And MR Ch.5 s.5.3.4	Manual Entry as per MR Ch.5 s.5.3.4.	Monthly	Due MP	13	13	13	13	
118	Emergency Energy Rebate	MR Ch.9 s.4.14.13 and MR Ch.5 s.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	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
119 MRP updated	Station Service Reimbursement Credit	MR Ch.9 ss.2.2.12-2.2.17	**The set of *charge types* 'c' has been updated** $= \{TD_{C,k,h}{}^{m,T} \times [\sum^{T2} (AQEW_{k,h}{}^{M,t}) / \sum_{K,h}{}^{T} (AQEW_{k,h}{}^{m,t} + SQEW_{k,h}{}^{i,t})]\}$ $+ \{TD_{C2,k,H}{}^{m,T} \times [\sum_{H2}{}^{T2} (AQEW_{k,h}{}^{M,t}) / \sum_{K,H}{}^{T} (AQEW_{k,h}{}^{m,t} + SQEW_{k,h}{}^{i,t})]\}$ $+ \{TD_{C3,k,H}{}^{m,T} \times [\sum_{H4}{}^{T2} (AQEW_{k,h}{}^{M,t}) / \sum_{K,H3}{}^{T} (AQEW_{k,h}{}^{m,t} + SQEW_{k,h}{}^{i,t})]\}$ **Where:** a. T = the set of all *metering intervals* in *settlement hour* 'h'; b. M = the eligible *generation station service delivery point* 'm' of *market participant* 'k'; c. C = the set of the following hourly uplift *charge type* 'c' as follows: 186,250,252,254,451,1120,1865,1950,1970,1977,1980,1981; d. $T2$ = the set of all *metering intervals* in *settlement hour* 'h' where the eligible *generation facility* or *electricity storage facility* was a net injector of *energy* into the *IESO-controlled grid*; e. K = the set of all *market participants*; f. $C2$ = the set of the following non-hourly monthly *charge type* 'c' as follows: 102,164,165,166,167,168,450,452,454,460,550,1116,1118,1188,1650,1941,9920; g. $C3$ = the set of the following daily *charge type* 'c' as follows: 1119,1850,1851,1960,1967,1971,1982,1986; h. H = the set of all *settlement hours* 'h' in the *billing period*; i. $H2$ = the set of all *settlement hours* 'h' in the *billing period* where the eligible *generation facility* or *electricity storage facility* was a net injector of *energy* into the *IESO-controlled grid*; j. $H3$ = the set of all *settlement hours* 'h' in the day; and k. $H4$ = the set of all *settlement hours* 'h' in the day where the eligible *generation facility* or *electricity storage facility* was a net injector of *energy* into the *IESO-controlled grid*.	Monthly	Due MP	13	N/A	N/A	N/A	
121	Northern Energy Advantage Program Settlement Amount	N/A	$= \sum_{M\,H}{}^{T} (AQEW_{mh}{}^{t}) \times (\text{Rate})$ Where: Rate is the program rate 'M' is the set of all *delivery points* 'm' for all *market participant*-eligible *facilities*.	Quarterly	Due MP	0	N/A	N/A	N/A	Eligibility, rates, and other implementation details subject to Ministry of Northern

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			'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'.							Development, Mines, Natural Resources and Forestry specifications.
123	MACD Enforcement Activity Amount	N/A	Manual entry based on the values submitted by MACD.	Monthly	Due MP	13	N/A	N/A	N/A	
142	Regulated Price Plan Settlement Amount	N/A	**NOTE:** The equation identified below applies 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* 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" • "Regulated Price Plan – Final Variance Settlement Amount" **Regulated Price Plan Settlement Amount:** $HPTSA\_NDL_{k,H} - \{ MIN [TLQ , \sum_H{}^{M,T} (AQEW_{k,h}{}^{m,t} - AQEI_{k,h}{}^{m,t} - \sum_s BCQ_{s,k,h}{}^{m,t})] \times RPP_{l=1} + MAX [0, \sum_H{}^{M,T} (AQEW_{k,h}{}^{m,t} - AQEI_{k,h}{}^{m,t} - \sum_s BCQ_{s,k,h}{}^{m,t}) - TLQ] \times RPP_{l=2} \}$	Monthly	Due LDCs Either way	13	N/A	N/A	N/A	Eligibility, rates, and other implementation details subject to government and OEB regulations.
143	NUG Contract Adjustment Settlement Amount	N/A	Manual entry based on the values submitted by *OEFC* via On-line settlement form "NUG Adjustment Amount Information", subject to Regulation.	Monthly	Due *OEFC*	13	N/A	N/A	N/A	Eligibility, rates, and other implementation details subject to government regulation.
144	Regulated Nuclear Generation	N/A		Interval or Hourly	Due OPG	13	N/A	N/A	N/A	Eligibility, rates, and other implementation details subject to

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
	Adjustment Amount		$$\sum_{H,M}\left(GRP \times AQEI_{k,h}^m\right) - \sum_{H}\left(HPTSA\{1\} + HPTSA\{2\}\right)$$ Where 'T' is the set of 12 *metering intervals* 't' during *settlement hour* 'h'.							government regulation.
145	Regulated Hydroelectric Generation Adjustment Amount	N/A	For *dispatchable resources*: $$\text{Regulated Payment} = \sum_{H,M}\left(GRP \times RTAvg_T\right) - \sum_{H}\left(HPTSA\{1\} + HPTSA\{2\}\right)$$ **Incentive Payment = DAM Incentive + RT Incentive** $$\text{DAM Incentive} = \sum_{H}\left(DAM\_QSI_{k,h}^m - DAMAvg_T\right) \times DAM\_LMP_{k,h}^m$$ $$\text{RT Incentive} = \left[\sum_{H,T}\left(\left[AQEI_{k,h}^m - AQEW_{k,h}^m - RTAvg_T\right] - \left(DAM\_QSI_{k,h}^m - DAM\_QSW_{k,h}^m - DAMAvg_T\right)\right) \times RT\_LMP_{k,h}^{m,t}\right]/12$$ For *non-dispatchable resources*: $$\text{Regulated Payment} = \sum_{H,M}\left(GRP \times RTAvg_T\right) - \sum_{H}\left(HPTSA\_NDL\right)$$ $$\text{Incentive Payment} = \sum_{H}\left(AQEI_{k,h}^m - RTAvg_T\right) \times \left(DAM\_OZP_{k,h}^m + LFDA\right)$$	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	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			Or $\text{Incentive Payment} = \sum_H \left(AQEI_{k,h}^m - RTAvg_T \right) \times RT\_OZP_{k,h}^m$; applicable when there is a DAM Failure. **Where:** $DAMAvg_T$ is the average DAM hourly scheduled MW over a trade day $RTAvg_T$ is the average hourly metered quantity over a trade day "H" is all hours in the trade day						
147	Class A – Global Adjustment Settlement Amount	N/A	$\sum_{H,M,C} TD * PDF_{k,m,d}$ 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, 1450, 1460, 1462, 1464, 1466, 1468, 1469, 1475, 1478.**	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.
148	Class B – Global Adjustment Settlement Amount	N/A	For Fort Frances Power Corporation Distribution Inc.: $(\sum_{H,M,C} TD - TD_{147})$ x $MAX((\sum_H^{M,T} AQEW_{k,h}^{m,t} + EGEI_k - EEQ), 0)$ / Class B Load For other Class B *Market Participants* and Distributors:	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	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			$(\Sigma_{H,M,C}TD - TD_{147})$ x $MAX((\Sigma_H^{M,T} AQEW_{k,h}^{m,t} + EGEI_k - GA\_AQEW_{g,k,h,M}^{m,t} - PGS_{h,M}),0)$ / Class B Load Class B Load = $(\Sigma_K (MAX(\Sigma_H^{M,T} AQEW_{k,h}^{m,t} + EGEI_k - EEQ - \Sigma_H^{M,T} GA\_AQEW_{g,k,h,M}^{m,t} - \Sigma_H PGS_{h,M},0))) - \Sigma_K U_k$ Where 'H' is the set of all *settlement hours* 'h' in the month. Where 'K' is the set of all *market participants* 'k'. 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, 1450, 1460, 1462, 1464, 1466, 1468, 1469, 1475, 1478.**							
149	Regulated Price Plan Retailer Settlement Amount	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.
164	Outage Cancellation/ Deferral Debit	MR Ch.5 s.6.7.4 and MR Ch.9 s.4.14.12	$\Sigma_{c,H}^{M,T} TD_{k,H,(114)}$ x $[(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}) / \Sigma_{k,H}^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t})]$ 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	
165	Unrecoverable Testing Costs Debit	MR Ch.9 s.4.14.12 and MR Ch.4 s.5.3.4	= $\Sigma_{H,c}^{M,T} TD_c$ x $[(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}) / \Sigma_{k,H}^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t})]$ 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	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
166	Tieline Maintenance Reliability Debit	MR Ch.9 s.4.14.12 and MR Ch.5 s.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	MR Ch.9 s.4.14.12 and MR Ch.5 s.2.3.3A	$= \sum_{H,c}^{M,T} TD_c \times [(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}) / \sum_{k,H}^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t})]$ 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'.	Monthly	Due *IESO*	13	N/A	0	13	
168	TR Market Shortfall Debit	MR Ch.9 s.6.16.6.3	**For loads:** $TRCAC_k = TRCAD_L \times \sum_H^{M,T} [(AQEW_{k,h}^{m,t}) / \sum_{K,H}^{M,T} (AQEW_{k,h}^{m,t})]$ **For exporters:** $TRCAC_k = TRCAD_E \times \sum_H^{I,T} [(SQEW_{k,h}^{i,t}) / \sum_{K,H}^{I,T} (SQEW_{k,h}^{i,t})]$ **Where:** a. $TRCAD_L = (\sum_K TD_C / \sum_K TD_{C,C1}) \times TRCAR$ b. $TRCAD_E = (\sum_K TD_{C1} / \sum_K TD_{C,C1}) \times TRCAR$ c. TRCAC = the *TR clearing account credit* (in \$ and up to 2 decimal places) collected from *market participant* 'k' in the current *energy market billing period*; d. TRCAR = the total dollar value (in \$ and up to 2 decimal places) of TR shortfall recovery from the *TR clearing account* authorized by the *IESO Board* in the current *energy market billing period*; e. C = the set of all monthly service *charge types* 'c' as follows: 650,651,652; and f. C1 = the set of all monthly export transmission *charge types* 'c' as follows: 653.	Monthly	Due *IESO*	13	N/A	0	13	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
169	Station Service Reimbursement Debit	MR Ch.9 ss.2.2.12-2.2.17 and 4.14.12	$= \sum_{H,c}^{M,T} TD_c \times [(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t} - GSSR\_AQEW_{k,h}^{i,t}) / \sum_{k,H}^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t} - GSSR\_AQEW_{k,h}^{i,t})]$ Where 'c' is *charge type* 119. 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	
171	Northern Energy Advantage Program Balancing Amount	N/A	$\sum_K TD_{k,121}$ Where 'k' is part of a subset of eligible *market participants* 'k'.	Quarterly	Due *IESO*	0	N/A	N/A	N/A	Eligibility, rates, and other implementation details subject to Ministry of Northern Development, Mines, Natural Resources and Forestry specifications.
173	MACD Enforcement Activity Balancing Amount	N/A	$\sum_K TD_{k123}$ 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	
186 MRP updated + name change	Intertie Failure Charge Uplift (INFCU)	MR Ch.9 s.3.11	**The set of *charge types* 'c' has been updated** $= \sum_{c}^{M,T} TD_{k,h,c} \times \left[\sum^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t} + RQ_{k,h}^{m,i,t}) / \sum_{K}^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}) \right]$ **Where:** a. C = the set of all *charge types* 'c' as follows: 1828,1829,1928,1929.	Hourly	Due MP	13	N/A	0	13	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
192	Regulated Price Plan Balancing Amount	N/A	$\Sigma_K TD_{k,142}$ Where 'K' is the set of all *market participants* 'k'. Where $TD_{k,142}$ 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	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	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	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	$\Sigma_K, TD_{k,147, 148} - \Sigma 197$ Where 'K' is the set of all *market participants* 'k'. Where $TD_{k,147, 148}$ 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.
197	Global Adjustment - Special Programs	N/A	$\Sigma_K \; TD_{k,1466}$ Where 'K' is the set of all *market participants* 'k'.	Monthly	Due *IESO*	0	N/A	N/A	N/A	Implementation details subject to government regulation.

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
	Balancing Amount		Where $TD_{k,1466}$ is the *settlement amount* of *charge type* 1466 for the month for *market participant* 'k'.							
199	Regulated Price Plan Retailer Balancing Amount	N/A	$\Sigma_K TD_{k,149}$ Where 'K' is the set of all *market participants* 'k'. Where $TD_{k,149}$ 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.
201	10 Minute Spinning Reserve Market Shortfall Rebate (HUSA)	MR Ch.9 s.3.11	$= \sum_C^{M,T} TD_{k,h,c} \ x \left[\sum^{M,T} \left(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t} + RQ_{k,h}^{m,i,t} \right) / \sum_K^{M,T} \left(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t} \right) \right]$ **Where:** a. C = the set of all *charge types* 'c' as follows: 251.	Hourly	Due MP	13	N/A	0	13	
203	10 Minute Non-spinning Reserve Market Shortfall Rebate (HUSA)	MR Ch.9 s.3.11	$= \sum_C^{M,T} TD_{k,h,c} \ x \left[\sum^{M,T} \left(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t} + RQ_{k,h}^{m,i,t} \right) / \sum_K^{M,T} \left(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t} \right) \right]$ **Where:** a. C = the set of all *charge types* 'c' as follows: 253.	Hourly	Due MP	13	N/A	0	13	
205	30 Minute Operating Reserve Market Shortfall Rebate (HUSA)	MR Ch.9 s.3.11	$= \sum_C^{M,T} TD_{k,h,c} \ x \left[\sum^{M,T} \left(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t} + RQ_{k,h}^{m,i,t} \right) / \sum_K^{M,T} \left(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t} \right) \right]$ **Where:** a. C = the set of all *charge types* 'c' as follows: 255.	Hourly	Due MP	13	N/A	0	13	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments

206
MRP updated
	10-Minute Spinning Non-Accessibility Settlement Amount
	
	(ORSCB)
		MR Ch.9 ss.3.10.1, 3.10.6-3.10.16	**The following is effective on the commencement of *market transition*. Refer to section 3 for the version in effect prior to the commencement of *market transition*.**
			
			Dispatchable Loads, Dispatchable Electricity Storage Resources, and Non-Aggregated Dispatchable Generation Resources
			
			$ORSCB_{r1,k,h}^{m,t} = Min[0, (TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t}) \times RT\_PROR_{r1,h}^{m,t}]$
			
			Where:
			1. For a *dispatchable electricity storage resource* or a non-aggregated *dispatchable generation resource*:
			  a. $TAOR_{k,h}^{m,t} = Max(0, MAX\_CAP_{k,h}^{m,t} - AQEI_{k,h}^{m,t})$
			  b. $MAX\_CAP_{k,h}^{m,t}$ = the maximum limit used in determining the *real-time schedule* in the *dispatch scheduling* and pricing process
			
			2. For a *dispatchable load*:
			  a. $TAOR_{k,h}^{m,t} = Max(0, AQEW_{k,h}^{m,t} - MC_{k,h}^{m,t})$
			  b. $MC_{k,h}^{m,t}$ = the minimum consumption level, equal to the quantity in the *price-quantity pair* where the *bid* price is the *maximum market clearing price*
			
			Aggregated Dispatchable Generation Resources that are not Pseudo-Units
			
			$ORSCB_{r1,k,h}^{m,t} = ORSCB_{k,h}^{M,t} \times \dfrac{ORIA_{r1,k,h}^{m,t}}{\sum_{R}^{M} ORIA_{r,k,h}^{m,t}}$
			
			Where:
			  i. M = the set of all *delivery points* 'm' of the aggregated group of *dispatchable generation resources*
				Interval	Due *IESO*	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments

			ii. $\quad TAOR_{k,h}^{m,t} = Max(0, MAX\_CAP_{k,h}^{m,t} - AQEI_{k,h}^{m,t})$
			
			 iii. $\quad MAX\_CAP_{k,h}^{m,t}$ = the maximum limit used in determining the *real-time schedule* in the *dispatch scheduling* and pricing pass
			
			 iv. $\quad ORIA_{r,k,h}^{m,t}$ is calculated as:
			     a. $\quad ORIA_{r1,k,h}^{m,t} = Min(0, TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t})$
			     b. $\quad ORIA_{r2,k,h}^{m,t} = Min[0, Max(0, TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t}) - RT\_QSOR_{r2,k,h}^{m,t}]$
			     c. $\quad ORIA_{r3,k,h}^{m,t} = Min[0, Max(0, TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t} - RT\_QSOR_{r2,k,h}^{m,t}) - RT\_QSOR_{r3,k,h}^{m,t}]$
			
			 v. $\quad ORSCB_{k,h}^{M,t} = Min[0, \sum_R^M (NORD_{r,k,h}^{m,t} \times RT\_PROR_{r,k,h}^{m,t})]$ and is the total amount of non-accessibility *operating reserve* for the aggregated group and is prorated in *charge types* 206, 208 and 210, as applicable.
			
			 vi. $\quad NORD_{r,k,h}^{m,t}$ is calculated as:
			     a. $\quad NORD_{r1,k,h}^{m,t} = Min(RT\_QSOR_{r1,k,h}^{m,t}, TAOR_{k,h}^{m,t}) + REAH_{r1,k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t}$
			     b. $\quad NORD_{r2,k,h}^{m,t} = Min[RT\_QSOR_{r2,k,h}^{m,t}, Max(0, TAOR_{k,h}^{m,t} - RT\_QSOR_{r2,k,h}^{m,t})] + REAH_{r2,k,h}^{m,t} - RT\_QSOR_{r2,k,h}^{m,t}$
			     c. $\quad NORD_{r3,k,h}^{m,t} = Min[RT\_QSOR_{r3,k,h}^{m,t}, Max(0, TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t} - RT\_QSOR_{r2,k,h}^{m,t})] + REAH_{r3,k,h}^{m,t} - RT\_QSOR_{r3,k,h}^{m,t}$
			
			 vii. $\quad REAH_{r,k,h}^{m,t}$ is calculated as follows for each type of *class r reserve*:
			 $\quad REAH_{r,k,h}^{m,t} = TREAH_{r,k,h}^{M,t} \times \dfrac{EAH_{k,h}^{m,t}}{\sum^M EAH_{k,h}^{m,t}}$
			
			 viii. $\quad EAH_{k,h}^{m,t} = Max(0, TAOR_{k,h}^{m,t} - \sum_R RT\_QSOR_{r,k,h}^{m,t})$
			
			 ix. $\quad$ When $\sum^M EAH_{k,h}^{m,t} = 0$, then $TREAH_{r,k,h}^{M,t} = 0$, and when $\sum^M EAH_{k,h}^{m,t} > 0$, then $TREAH_{r,k,h}^{M,t}$ is calculated as follows:
			     a. $\quad TREAH_{r1,k,h}^{M,t} = Min(\sum^M EAH_{k,h}^{m,t}, (-1) \times \sum^M ORIA_{r1,k,h}^{m,t})$
			     b. $\quad TREAH_{r2,k,h}^{M,t} = Min[(\sum^M EAH_{k,h}^{m,t}) - TREAH_{r1,k,h}^{M,t}, (-1) \times \sum^M ORIA_{r2,k,h}^{m,t}]$
			     c. $\quad TREAH_{r3,k,h}^{M,t} = Min[(\sum^M EAH_{k,h}^{m,t}) - TREAH_{r1,k,h}^{M,t} - TREAH_{r2,k,h}^{M,t}, (-1) \times \sum^M ORIA_{r3,k,h}^{m,t}]$						

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments

			Dispatchable Generation Resources that are Pseudo-Units
			
			A. For a combustion turbine *resource:*
			
			$$ORSCB_{r1,k,h}^{c,t} = ORSCB_{k,h}^{M,t} \times \frac{ORIA_{r1,k,h}^{c,t}}{\sum_{R}^{M}\left(ORIA_{r,k,h}^{c,t} + ORIA_{r,k,h}^{s,t}\right)}$$
			
			Where:
			a. 'M' = the set of all *delivery points* 'c' and 's' of the aggregated group of *dispatchable generation resources*
			b. $ORIA_{r,k,h}^{c,t}$ is calculated as:
			
			    i. $ORIA_{r1,k,h}^{c,t} = Min\left(0, TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t}\right)$
			    ii. $ORIA_{r2,k,h}^{c,t} = Min\left[0, Max\left(0, TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t}\right) - RT\_QSOR_{r2,k,h}^{c,t}\right]$
			    iii. $ORIA_{r3,k,h}^{c,t} = Min\left[0, Max\left(0, TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t} - RT\_QSOR_{r2,k,h}^{c,t}\right) - RT\_QSOR_{r3,k,h}^{c,t}\right]$
			
			    and where:
			    i. $TAOR\_CT_{k,h}^{c,t} = Max\left(0, MAX\_CAP_{k,h}^{c,t} - AQEI_{k,h}^{c,t}\right)$ when $AQEI_{k,h}^{c,t} >=$ *minimum loading point*
			    ii. $TAOR\_CT_{k,h}^{c,t} = 0$ when $AQEI_{k,h}^{c,t} <$ *minimum loading point*
			
			B. For a steam turbine *resource:*
			
			$$ORSCB_{r1,k,h}^{s,t} = ORSCB_{k,h}^{M,t} \times \frac{ORIA_{r1,k,h}^{s,t}}{\sum_{R}^{M}\left(ORIA_{r,k,h}^{c,t} + ORIA_{r,k,h}^{s,t}\right)}$$							

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			Where:							

Where:

a. 'M' = the set of all *delivery points* 'c' and 's' of the aggregated group of *dispatchable generation resources*

b. $ORIA_{r,k,h}^{s,t}$ is calculated as:

  i. $ORIA_{r1,k,h}^{s,t} = Min(0, TAOR\_ST_{k,h}^{s,t} - RT\_QSOR_{r1,k,h}^{s,t})$

  ii. $ORIA_{r2,k,h}^{s,t} = Min[0, Max(0, TAOR\_ST_{k,h}^{s,t} - RT\_QSOR_{r1,k,h}^{s,t}) - RT\_QSOR_{r2,k,h}^{s,t}]$

  iii. $ORIA_{r3,k,h}^{s,t} = Min[0, Max(0, TAOR\_ST_{k,h}^{s,t} - RT\_QSOR_{r1,k,h}^{s,t} - RT\_QSOR_{r2,k,h}^{s,t}) - RT\_QSOR_{r3,k,h}^{s,t}]$

and where:

  i. $TAOR\_ST_{k,h}^{s,t} = Max\left[0, \left(\sum_{D}^{P1} RT\_ORRQ_{k,d}^{p}\right) - \left(\sum^{C1} MAX\_CAP_{k,h}^{c,t}\right) - AQEI_{k,h}^{s,t}\right]$

  a. P1 = the set of the *resource's pseudo-units* 'p' where $AQEI_{k,h}^{c,t} >= $ *minimum loading point* and is not operating in *single cycle mode*;

  b. C1 = the set of the *resource's* combustion turbine *resources* 'c' associated with the steam turbine *resource* and $AQEI_{k,h}^{c,t} >= $ *minimum loading point* and is not operating in *single cycle mode*; and

  c. D = the set of *pseudo-unit* operating regions 'd1', 'd2', and 'd3'.

For both the combustion turbine *resource* and the steam turbine *resource*

$ORSCB_{k,h}^{M,t}$ is the total amount of non-accessibility *operating reserve* for the aggregated group and is prorated in *charge types* 206, 208 and 210, as applicable, to determine the *operating reserve* non-accessibility charge for each combustion turbine *resource* and steam turbine *resource* of the aggregated group.

$$ORSCB_{k,h}^{M,t} = Min\left[0, \sum_{R}^{M}\left((NORD_{r,k,h}^{c,t} \times RT\_PROR_{r\,k,h}^{c,t}) + (NORD_{r,k,h}^{s,t} \times RT\_PROR_{r,k,h}^{s,t})\right)\right]$$

Where:

a. 'M' = the set of all *delivery points* 'c' and 's' of the aggregated group of *dispatchable generation resources*

b. $NORD_{r,k,h}^{c,t}$ for the combustion turbine *resource* is calculated as:

  i. $NORD_{r1,k,h}^{c,t} = Min(RT\_QSOR_{r1,k,h}^{c,t}, TAOR\_CT_{k,h}^{c,t}) + REAH_{r1,k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t}$

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			ii. $NORD_{r2,k,h}^{c,t} = Min[RT\_QSOR_{r2,k,h}^{c,t}, Max(0, TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t})] + REAH_{r2,k,h}^{c,t} - RT\_QSOR_{r2,k,h}^{c,t}$ iii. $NORD_{r3,k,h}^{c,t} = Min[RT\_QSOR_{r3,k,h}^{c,t}, Max(0, TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t} - RT\_QSOR_{r2,k,h}^{c,t})] + REAH_{r3,k,h}^{c,t} - RT\_QSOR_{r3,k,h}^{c,t}$ c. $NORD_{r,k,h}^{s,t}$ for the steam turbine *resource* is calculated as: i. $NORD_{r1,k,h}^{s,t} = Min(RT\_QSOR_{r1,k,h}^{s,t}, TAOR\_CT_{k,h}^{s,t}) + REAH_{r1,k,h}^{s,t} - RT\_QSOR_{r1,k,h}^{s,t}$ ii. $NORD_{r2,k,h}^{s,t} = Min[RT\_QSOR_{r2,k,h}^{s,t}, Max(0, TAOR\_CT_{k,h}^{s,t} - RT\_QSOR_{r1,k,h}^{s,t})] + REAH_{r2,k,h}^{s,t} - RT\_QSOR_{r2,k,h}^{s,t}$ iii. $NORD_{r3,k,h}^{s,t} = Min[RT\_QSOR_{r3,k,h}^{s,t}, Max(0, TAOR\_CT_{k,h}^{s,t} - RT\_QSOR_{r1,k,h}^{s,t} - RT\_QSOR_{r2,k,h}^{s,t})] + REAH_{r3,k,h}^{s,t} - RT\_QSOR_{r3,k,h}^{s,t}$ d. $REAH_{r,k,h}^{c,t}$ for the combustion turbine *resource* is calculated as follows for each type of *class r reserve*: $REAH_{r,k,h}^{c,t} = TREAH_{r,k,h}^{M,t} \times \dfrac{EAH_{k,h}^{c,t}}{\sum^M (EAH_{k,h}^{c,t} + EAH_{k,h}^{s,t})}$ e. $REAH_{r,k,h}^{s,t}$ for the steam turbine *resource* is calculated as follows for each type of *class r reserve*: $REAH_{r,k,h}^{s,t} = TREAH_{r,k,h}^{M,t} \times \dfrac{EAH_{k,h}^{s,t}}{\sum^M (EAH_{k,h}^{c,t} + EAH_{k,h}^{s,t})}$ f. $EAH_{k,h}^{c,t} = Max(0, TAOR\_CT_{k,h}^{c,t} - \sum_R RT\_QSOR_{r,k,h}^{c,t})$ for the combustion turbine *resource* g. $EAH_{k,h}^{s,t} = Max(0, TAOR\_ST_{k,h}^{s,t} - \sum_R RT\_QSOR_{r,k,h}^{s,t})$ for the steam turbine *resource* h. When $\sum^M(EAH_{k,h}^{c,t} + EAH_{k,h}^{s,t}) = 0$, then $TREAH_{r,k,h}^{M,t} = 0$, and when $\sum^M(EAH_{k,h}^{c,t} + EAH_{k,h}^{s,t}) > 0$, then i. $TREAH_{r1,k,h}^{M,t} = Min(\sum^M(EAH_{k,h}^{c,t} + EAH_{k,h}^{s,t}), (-1) \times \sum^M(ORIA_{r1,k,h}^{c,t} + ORIA_{r1,k,h}^{s,t}))$ ii. $TREAH_{r2,k,h}^{M,t} = Min[(\sum^M(EAH_{k,h}^{c,t} + EAH_{k,h}^{s,t})) - TREAH_{r1,k,h}^{M,t}, (-1) \times \sum^M(ORIA_{r2,k,h}^{c,t} + ORIA_{r2,k,h}^{s,t})]$ iii. $TREAH_{r3,k,h}^{M,t} = Min[(\sum^M(EAH_{k,h}^{c,t} + EAH_{k,h}^{s,t})) - TREAH_{r1,k,h}^{M,t} - TREAH_{r2,k,h}^{M,t}, (-1) \times \sum^M(ORIA_{r3,k,h}^{c,t} + ORIA_{r3,k,h}^{s,t})]$						

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments

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MRP updated
	10-Minute Non-Spinning Non-Accessibility Settlement Amount
	
	(ORSCB)
		MR Ch.9 ss.3.10.1, 3.10.6-3.10.16	**The following is effective on the commencement of *market transition*. Refer to section 3 for the version in effect prior to the commencement of *market transition*.**
			
			Dispatchable Loads, Dispatchable Electricity Storage Resources, and Non-Aggregated Dispatchable Generation Resources
			
			$$ORSCB_{r2,k,h}^{m,t} = Min\{0, [Max(0, TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t}) - RT\_QSOR_{r2,k,h}^{m,t}] \times RT\_PROR_{r2,h}^{m,t}\}$$
			
			Where:
			1. **For a *dispatchable electricity storage resource* or a non-aggregated *dispatchable generation resource*:**
			  a. $TAOR_{k,h}^{m,t} = Max(0, MAX\_CAP_{k,h}^{m,t} - AQEI_{k,h}^{m,t})$
			  b. $MAX\_CAP_{k,h}^{m,t}$ = the maximum limit used in determining the *real-time schedule* in the *dispatch scheduling* and pricing process
			
			2. **For a *dispatchable load*:**
			  a. $TAOR_{k,h}^{m,t} = Max(0, AQEW_{k,h}^{m,t} - MC_{k,h}^{m,t})$
			  b. $MC_{k,h}^{m,t}$ = the minimum consumption level, equal to the quantity in the *price-quantity pair* where the *bid* price is the *maximum market clearing price*
			
			Aggregated Dispatchable Generation Resources that are not Pseudo-Units
			
			$$ORSCB_{r2,k,h}^{m,t} = ORSCB_{k,h}^{M,t} \times \frac{ORIA_{r2,k,h}^{m,t}}{\sum_{R}^{M} ORIA_{r,k,h}^{m,t}}$$
			
			Where:
			  i. 'M' = the set of all *delivery points* 'm' of the aggregated group of *dispatchable generation resources*
				Interval	Due *IESO*	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments

			ii. $TAOR_{k,h}^{m,t} = Max\left(0, MAX\_CAP_{k,h}^{m,t} - AQEI_{k,h}^{m,t}\right)$
			
			 iii. $MAX\_CAP_{k,h}^{m,t}$ = the maximum limit used in determining the *real-time schedule* in the *dispatch scheduling* and pricing process
			
			 iv. $ORIA_{r,k,h}^{m,t}$ is calculated as:
			
			   a. $ORIA_{r1,k,h}^{m,t} = Min(0, TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t})$
			
			   b. $ORIA_{r2,k,h}^{m,t} = Min[0, Max(0, TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t}) - RT\_QSOR_{r2,k,h}^{m,t}]$
			
			   c. $ORIA_{r3,k,h}^{m,t} = Min[0, Max(0, TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t} - RT\_QSOR_{r2,k,h}^{m,t}) - RT\_QSOR_{r3,k,h}^{m,t}]$
			
			 v. $ORSCB_{k,h}^{M,t} = Min[0, \sum_{R}^{M}(NORD_{r,k,h}^{m,t} \times RT\_PROR_{r,k,h}^{m,t})]$ and is the total amount of non-accessibility *operating reserve* for the aggregated group and is prorated in *charge types* 206, 208 and 210, as applicable.
			
			 vi. $NORD_{r,k,h}^{m,t}$ is calculated as:
			
			   a. $NORD_{r1,k,h}^{m,t} = Min(RT\_QSOR_{r1,k,h}^{m,t}, TAOR_{k,h}^{m,t}) + REAH_{r1,k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t}$
			
			   b. $NORD_{r2,k,h}^{m,t} = Min[RT\_QSOR_{r2,k,h}^{m,t}, Max(0, TAOR_{k,h}^{m,t} - RT\_QSOR_{r2,k,h}^{m,t})] + REAH_{r2,k,h}^{m,t} - RT\_QSOR_{r2,k,h}^{m,t}$
			
			   c. $NORD_{r3,k,h}^{m,t} = Min[RT\_QSOR_{r3,k,h}^{m,t}, Max(0, TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t} - RT\_QSOR_{r2,k,h}^{m,t})] + REAH_{r3,k,h}^{m,t} - RT\_QSOR_{r3,k,h}^{m,t}$
			
			 vii. $REAH_{r,k,h}^{m,t}$ is calculated as follows for each type of *class r reserve*:
			
			 $REAH_{r,k,h}^{m,t} = TREAH_{r,k,h}^{M,t} \times \dfrac{EAH_{k,h}^{m,t}}{\sum^{M} EAH_{k,h}^{m,t}}$
			
			 viii. $EAH_{k,h}^{m,t} = Max(0, TAOR_{k,h}^{m,t} - \sum_{R} RT\_QSOR_{r,k,h}^{m,t})$
			
			 ix. When $\sum^{M} EAH_{k,h}^{m,t} = 0$, then $TREAH_{r,k,h}^{M,t} = 0$, and when $\sum^{M} EAH_{k,h}^{m,t} > 0$, then $TREAH_{r,k,h}^{M,t}$ is calculated as follows:
			
			   a. $TREAH_{r1,k,h}^{M,t} = Min(\sum^{M} EAH_{k,h}^{m,t}, (-1) \times \sum^{M} ORIA_{r1,k,h}^{m,t})$
			
			   b. $TREAH_{r2,k,h}^{M,t} = Min[(\sum^{M} EAH_{k,h}^{m,t}) - TREAH_{r1,k,h}^{M,t}, (-1) \times \sum^{M} ORIA_{r2,k,h}^{m,t}]$
			
			   c. $TREAH_{r3,k,h}^{M,t} = Min[(\sum^{M} EAH_{k,h}^{m,t}) - TREAH_{r1,k,h}^{M,t} - TREAH_{r2,k,h}^{M,t}, (-1) \times \sum^{M} ORIA_{r3,k,h}^{m,t}]$							

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments

			Dispatchable Generation Resources that are Pseudo-Units
			
			A. For a combustion turbine *resource:*
			
			$ORSCB_{r2,k,h}^{c,t} = ORSCB_{k,h}^{M,t} \times \dfrac{ORIA_{r2,k,h}^{c,t}}{\sum_R^M (ORIA_{r,k,h}^{c,t} + ORIA_{r,k,h}^{s,t})}$
			
			Where:
			a. 'M' = the set of all *delivery points* 'c' and 's' of the aggregated group of *dispatchable generation resources*;
			b. $ORIA_{r,k,h}^{c,t}$ is calculated as:
			
			   i. $ORIA_{r1,k,h}^{c,t} = Min(0, TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t})$
			   ii. $ORIA_{r2,k,h}^{c,t} = Min[0, Max(0, TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t}) - RT\_QSOR_{r2,k,h}^{c,t}]$
			   iii. $ORIA_{r3,k,h}^{c,t} = Min[0, Max(0, TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t} - RT\_QSOR_{r2,k,h}^{c,t}) - RT\_QSOR_{r3,k,h}^{c,t}]$
			
			  and where:
			   i. $TAOR\_CT_{k,h}^{c,t} = Max(0, MAX\_CAP_{k,h}^{c,t} - AQEI_{k,h}^{c,t})$ when $AQEI_{k,h}^{c,t} >=$ *minimum loading point*
			   ii. $TAOR\_CT_{k,h}^{c,t} = 0$ when $AQEI_{k,h}^{c,t} <$ *minimum loading point*
			
			B. For a steam turbine *resource:*
			
			$ORSCB_{r2,k,h}^{s,t} = ORSCB_{k,h}^{M,t} \times \dfrac{ORIA_{r2,k,h}^{s,t}}{\sum_R^M (ORIA_{r,k,h}^{c,t} + ORIA_{r,k,h}^{s,t})}$
			
			Where:
			a. 'M' = the set of all *delivery points* 'c' and 's' of the aggregated group of *dispatchable generation resources*
			b. $ORIA_{r,k,h}^{s,t}$ is calculated as:
			
			   i. $ORIA_{r1,k,h}^{s,t} = Min(0, TAOR\_ST_{k,h}^{s,t} - RT\_QSOR_{r1,k,h}^{s,t})$							

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			ii. $ORIA_{r2,k,h}^{s,t} = Min[0, Max(0, TAOR\_ST_{k,h}^{s,t} - RT\_QSOR_{r1,k,h}^{s,t}) - RT\_QSOR_{r2,k,h}^{s,t}]$ iii. $ORIA_{r3,k,h}^{s,t} = Min[0, Max(0, TAOR\_ST_{k,h}^{s,t} - RT\_QSOR_{r1,k,h}^{s,t} - RT\_QSOR_{r2,k,h}^{s,t}) - RT\_QSOR_{r3,k,h}^{s,t}]$ **and where:** i. $TAOR\_ST_{k,h}^{s,t} = Max[0, (\sum_D^{P1} RT\_ORRQ_{k,d}^p) - (\sum^{C1} MAX\_CAP_{k,h}^{c,t}) - AQEI_{k,h}^{s,t}]$ a. P1 = the set of the *resource's pseudo-units* 'p' where $AQEI_{k,h}^{c,t}$ >= *minimum loading point* and is not operating in single cycle mode; b. C1 = the set of the *resource's* combustion turbine *resources* 'c' associated with the steam turbine *resource* and $AQEI_{k,h}^{c,t}$ >= *minimum loading point* and is not operating in single cycle mode; and c. D = the set of *pseudo-unit* operating regions 'd1', 'd2', and 'd3'. **For both the combustion turbine *resource* and the steam turbine *resource*** $ORSCB_{k,h}^{M,t}$ is the total amount of non-accessibility *operating reserve* for the aggregated group and is prorated in *charge types* 206, 208 and 210, as applicable, to determine the *operating reserve* non-accessibility charge for each combustion turbine *resource* and steam turbine *resource* of the aggregated group. $ORSCB_{k,h}^{M,t} = Min\left[0, \sum_R^M \left((NORD_{r,k,h}^{c,t} \times RT\_PROR_{r,k,h}^{c,t}) + (NORD_{r,k,h}^{s,t} \times RT\_PROR_{r,k,h}^{s,t})\right)\right]$ **Where:** a. 'M' = the set of all *delivery points* 'c' and 's' of the aggregated group of *dispatchable generation resources* b. $NORD_{r,k,h}^{c,t}$ for the combustion turbine *resource* is calculated as: i. $NORD_{r1,k,h}^{c,t} = Min(RT\_QSOR_{r1,k,h}^{c,t}, TAOR\_CT_{k,h}^{c,t}) + REAH_{r1,k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t}$ ii. $NORD_{r2,k,h}^{c,t} = Min[RT\_QSOR_{r2,k,h}^{c,t}, Max(0, TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t})] + REAH_{r2,k,h}^{c,t} - RT\_QSOR_{r2,k,h}^{c,t}$ iii. $NORD_{r3,k,h}^{c,t} = Min[RT\_QSOR_{r3,k,h}^{c,t}, Max(0, TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t} - RT\_QSOR_{r2,k,h}^{c,t})] + REAH_{r3,k,h}^{c,t} - RT\_QSOR_{r3,k,h}^{c,t}$						

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments

			c. $NORD_{r,k,h}^{s,t}$ for the steam turbine *resource* is calculated as:
			
			  i. $NORD_{r1,k,h}^{s,t} = Min(RT\_QSOR_{r1,k,h}^{s,t}, TAOR\_CT_{k,h}^{s,t}) + REAH_{r1,k,h}^{s,t} - RT\_QSOR_{r1,k,h}^{s,t}$
			
			  ii. $NORD_{r2,k,h}^{s,t} = Min[RT\_QSOR_{r2,k,h}^{s,t}, Max(0, TAOR\_CT_{k,h}^{s,t} - RT\_QSOR_{r1,k,h}^{s,t})] + REAH_{r2,k,h}^{s,t} - RT\_QSOR_{r2,k,h}^{s,t}$
			
			  iii. $NORD_{r3,k,h}^{s,t} = Min[RT\_QSOR_{r3,k,h}^{s,t}, Max(0, TAOR\_CT_{k,h}^{s,t} - RT\_QSOR_{r1,k,h}^{s,t} - RT\_QSOR_{r2,k,h}^{s,t})] + REAH_{r3,k,h}^{s,t} - RT\_QSOR_{r3,k,h}^{s,t}$
			
			d. $REAH_{r,k,h}^{c,t}$ for the combustion turbine *resource* is calculated as follows for each type of *class r reserve*:
			
			$REAH_{r,k,h}^{c,t} = TREAH_{r,k,h}^{M,t} \times \dfrac{EAH_{k,h}^{c,t}}{\sum^M (EAH_{k,h}^{c,t} + EAH_{k,h}^{s,t})}$
			
			e. $REAH_{r,k,h}^{s,t}$ for the steam turbine *resource* is calculated as follows for each type of *class r reserve*:
			
			$REAH_{r,k,h}^{s,t} = TREAH_{r,k,h}^{M,t} \times \dfrac{EAH_{k,h}^{s,t}}{\sum^M (EAH_{k,h}^{c,t} + EAH_{k,h}^{s,t})}$
			
			f. $EAH_{k,h}^{c,t} = Max(0, TAOR\_CT_{k,h}^{c,t} - \sum_R RT\_QSOR_{r,k,h}^{c,t})$ for the combustion turbine *resource*
			
			g. $EAH_{k,h}^{s,t} = Max(0, TAOR\_ST_{k,h}^{s,t} - \sum_R RT\_QSOR_{r,k,h}^{s,t})$ for the steam turbine *resource*
			
			h. When $\sum^M (EAH_{k,h}^{c,t} + EAH_{k,h}^{s,t}) = 0$, then $TREAH_{r,k,h}^{M,t} = 0$, and when $\sum^M (EAH_{k,h}^{c,t} + EAH_{k,h}^{s,t}) > 0$, then
			
			  i. $TREAH_{r1,k,h}^{M,t} = Min(\sum^M (EAH_{k,h}^{c,t} + EAH_{k,h}^{s,t}), (-1) \times \sum^M (ORIA_{r1,k,h}^{s,t} + ORIA_{r1,k,h}^{s,t}))$
			
			  ii. $TREAH_{r2,k,h}^{M,t} = Min[(\sum^M (EAH_{k,h}^{c,t} + EAH_{k,h}^{s,t})) - TREAH_{r1,k,h}^{M,t}, (-1) \times \sum^M (ORIA_{r2,k,h}^{c,t} + ORIA_{r2,k,h}^{s,t})]$
			
			  iii. $TREAH_{r3,k,h}^{M,t} = Min[(\sum^M (EAH_{k,h}^{c,t} + EAH_{k,h}^{s,t})) - TREAH_{r1,k,h}^{M,t} - TREAH_{r2,k,h}^{M,t}, (-1) \times \sum^M (ORIA_{r3,k,h}^{c,t} + ORIA_{r3,k,h}^{s,t})]$							

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments

210 MRP updated	30-Minute Non-Accessibility Settlement Amount (ORSCB)	MR Ch.9 ss.3.10.1, 3.10.6-3.10.16	****The following is effective on the commencement of *market transition*. Refer to section 3 for the version in effect prior to the commencement of *market transition*.****
			
			Dispatchable Loads, Dispatchable Electricity Storage, and Non-Aggregated Dispatchable Generation Resources
			
			$ORSCB_{r3,k,h}^{m,t} = Min\{0, [Max(0, TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t} - RT\_QSOR_{r2,k,h}^{m,t}) - RT\_QSOR_{r3,k,h}^{m,t}] \times RT\_PROR_{r3,h}^{m,t}\}$
			
			Where:
			1. **For a *dispatchable electricity storage resource* or a non-aggregated *dispatchable generation resource*:**
			  a. $TAOR_{k,h}^{m,t} = Max(0, MAX\_CAP_{k,h}^{m,t} - AQEI_{k,h}^{m,t})$
			  b. $MAX\_CAP_{k,h}^{m,t}$ = the maximum limit used in determining the *real-time schedule* in the *dispatch scheduling* and pricing process
			2. **For a *dispatchable load*:**
			  a. $TAOR_{k,h}^{m,t} = Max(0, AQEW_{k,h}^{m,t} - MC_{k,h}^{m,t})$
			  b. $MC_{k,h}^{m,t}$ = the minimum consumption level, equal to the quantity in the *price-quantity pair* where the *bid* price is the *maximum market clearing price*
			
			Aggregated Dispatchable Generation Resources that are not Pseudo-Units
			
			$ORSCB_{r3,k,h}^{m,t} = ORSCB_{k,h}^{M,t} \times \dfrac{ORIA_{r3,k,h}^{m,t}}{\sum_R^M ORIA_{r,k,h}^{m,t}}$
			
			Where:
			  i. 'M' = the set of all *delivery points* 'm' of the aggregated group of *dispatchable generation resources*
			  ii. $TAOR_{k,h}^{m,t} = Max(0, MAX\_CAP_{k,h}^{m,t} - AQEI_{k,h}^{m,t})$
				Interval	Due *IESO*	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			iii. $MAX\_CAP_{k,h}^{m,t}$ = the maximum limit used in determining the *real-time schedule* in the *dispatch scheduling* and pricing process iv. $ORIA_{r,k,h}^{m,t}$ is calculated as: a. $ORIA_{r1,k,h}^{m,t} = Min\left(0, TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t}\right)$ b. $ORIA_{r2,k,h}^{m,t} = Min\left[0, Max\left(0, TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t}\right) - RT\_QSOR_{r2,k,h}^{m,t}\right]$ c. $ORIA_{r3,k,h}^{m,t} = Min\left[0, Max\left(0, TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t} - RT\_QSOR_{r2,k,h}^{m,t}\right) - RT\_QSOR_{r3,k,h}^{m,t}\right]$ v. $ORSCB_{k,h}^{M,t} = Min[0, \sum_{R}^{M}(NORD_{r,k,h}^{m,t} \times RT\_PROR_{r,k,h}^{m,t})]$ and is the total amount of non-accessibility *operating reserve* for the aggregated group and is prorated in *charge types* 206, 208 and 210, as applicable. vi. $NORD_{r,k,h}^{m,t}$ is calculated as: a. $NORD_{r1,k,h}^{m,t} = Min(RT\_QSOR_{r1,k,h}^{m,t}, TAOR_{k,h}^{m,t}) + REAH_{r1,k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t}$ b. $NORD_{r2,k,h}^{m,t} = Min[RT\_QSOR_{r2,k,h}^{m,t}, Max(0, TAOR_{k,h}^{m,t} - RT\_QSOR_{r2,k,h}^{m,t})] + REAH_{r2,k,h}^{m,t} - RT\_QSOR_{r2,k,h}^{m,t}$ c. $NORD_{r3,k,h}^{m,t} = Min[RT\_QSOR_{r3,k,h}^{m,t}, Max(0, TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t} - RT\_QSOR_{r2,k,h}^{m,t})] + REAH_{r3\ k,h}^{m,t} - RT\_QSOR_{r3,k,h}^{m,t}$ vii. $REAH_{r,k,h}^{m,t}$ is calculated as follows for each type of *class r reserve*: $REAH_{r,k,h}^{m,t} = TREAH_{r,k,h}^{M,t} \times \dfrac{EAH_{k,h}^{m,t}}{\sum^{M} EAH_{k,h}^{m,t}}$ viii. $EAH_{k,h}^{m,t} = Max(0, TAOR_{k,h}^{m,t} - \sum_{R} RT\_QSOR_{r,k,h}^{m,t})$ ix. When $\sum^{M} EAH_{k,h}^{m,t} = 0$, then $TREAH_{r,k,h}^{M,t} = 0$, and when $\sum^{M} EAH_{k,h}^{m,t} > 0$, then $TREAH_{r,k,h}^{M,t}$ is calculated as follows: a. $TREAH_{r1,k,h}^{M,t} = Min(\sum^{M} EAH_{k,h}^{m,t}, (-1) \times \sum^{M} ORIA_{r1,k,h}^{m,t})$ b. $TREAH_{r2,k,h}^{M,t} = Min[(\sum^{M} EAH_{k,h}^{m,t}) - TREAH_{r1,k,h}^{M,t}, (-1) \times \sum^{M} ORIA_{r2,k,h}^{m,t}]$ c. $TREAH_{r3,k,h}^{M,t} = Min[(\sum^{M} EAH_{k,h}^{m,t}) - TREAH_{r1,k,h}^{M,t} - TREAH_{r2,k,h}^{M,t}, (-1) \times \sum^{M} ORIA_{r3,k,h}^{m,t}]$						

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments

			Dispatchable Generation Resources that are Pseudo-Units
			
			A. For a combustion turbine *resource:*
			
			$$ORSCB_{r3,k,h}^{c,t} = ORSCB_{k,h}^{M,t} \times \frac{ORIA_{r3,k,h}^{c,t}}{\sum_{R}^{M}\left(ORIA_{r,k,h}^{c,t} + ORIA_{r,k,h}^{s,t}\right)}$$
			
			Where:
			a. 'M' = the set of all *delivery points* 'c' and 's' of the aggregated group of *dispatchable generation resources*
			b. $ORIA_{r,k,h}^{c,t}$ is calculated as:
			  i. $ORIA_{r1,k,h}^{c,t} = Min\left(0, TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t}\right)$
			  ii. $ORIA_{r2,k,h}^{c,t} = Min\left[0, Max\left(0, TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t}\right) - RT\_QSOR_{r2,k,h}^{c,t}\right]$
			  iii. $ORIA_{r3,k,h}^{c,t} = Min\left[0, Max\left(0, TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t} - RT\_QSOR_{r2,k,h}^{c,t}\right) - RT\_QSOR_{r3,k,h}^{c,t}\right]$
			
			  and where:
			  i. $TAOR\_CT_{k,h}^{c,t} = Max\left(0, MAX\_CAP_{k,h}^{c,t} - AQEI_{k,h}^{c,t}\right)$ when $AQEI_{k,h}^{c,t}$ >= *minimum loading point*
			  ii. $TAOR\_CT_{k,h}^{c,t} = 0$ when $AQEI_{k,h}^{c,t}$ < *minimum loading point*
			
			B. For a steam turbine *resource:*
			
			$$ORSCB_{r3,k,h}^{s,t} = ORSCB_{k,h}^{M,t} \times \frac{ORIA_{r3,k,h}^{s,t}}{\sum_{R}^{M}\left(ORIA_{r,k,h}^{c,t} + ORIA_{r,k,h}^{s,t}\right)}$$
			
			Where:
			a. 'M' = the set of all *delivery points* 'c' and 's' of the aggregated group of *dispatchable generation resources*							

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments

			b. $ORIA_{r,k,h}^{s,t}$ is calculated as:
			
			i. $ORIA_{r1,k,h}^{s,t} = Min(0, TAOR\_ST_{k,h}^{s,t} - RT\_QSOR_{r1,k,h}^{s,t})$
			
			ii. $ORIA_{r2,k,h}^{s,t} = Min[0, Max(0, TAOR\_ST_{k,h}^{s,t} - RT\_QSOR_{r1,k,h}^{s,t}) - RT\_QSOR_{r2,k,h}^{s,t}]$
			
			iii. $ORIA_{r3,k,h}^{s,t} = Min[0, Max(0, TAOR\_ST_{k,h}^{s,t} - RT\_QSOR_{r1,k,h}^{s,t} - RT\_QSOR_{r2,k,h}^{s,t}) - RT\_QSOR_{r3,k,h}^{s,t}]$
			
			and where:
			
			i. $TAOR\_ST_{k,h}^{s,t} = Max[0, (\sum_{D}^{P1} RT\_ORRQ_{k,d}^{p}) - (\sum^{C1} MAX\_CAP_{k,h}^{c,t}) - AQEI_{k,h}^{s,t}]$
			
			  a. P1 = the set of the *resource's pseudo-units* 'p' where $AQEI_{k,h}^{c,t}$ >= *minimum loading point* and is not operating in single cycle mode;
			
			  b. C1 = the set of the *resource's* combustion turbine *resources* 'c' associated with the steam turbine *resource* and $AQEI_{k,h}^{c,t}$ >= *minimum loading point* and is not operating in single cycle mode; and
			
			  c. D = the set of *pseudo-unit* operating regions 'd1', 'd2', and 'd3'.
			
			For both the combustion turbine *resource* and the steam turbine *resource*
			
			$ORSCB_{k,h}^{M,t}$ is the total amount of non-accessibility *operating reserve* for the aggregated group and is prorated in *charge types* 206, 208 and 210, as applicable, to determine the *operating reserve* non-accessibility charge for each combustion turbine *resource* and steam turbine *resource* of the aggregated group.
			
			$ORSCB_{k,h}^{M,t} = Min[0, \sum_{R}^{M} ((NORD_{r,k,h}^{c,t} \times RT\_PROR_{r,k,h}^{c,t}) + (NORD_{r,k,h}^{s,t} \times RT\_PROR_{r,k,h}^{s,t}))]$
			
			Where:
			
			a. 'M' = the set of all *delivery points* 'c' and 's' of the aggregated group of *dispatchable generation resources*
			
			b. $NORD_{r,k,h}^{c,t}$ for the combustion turbine *resource* is calculated as:
			
			i. $NORD_{r1,k,h}^{c,t} = Min(RT\_QSOR_{r1,k,h}^{c,t}, TAOR\_CT_{k,h}^{c,t}) + REAH_{r1,k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t}$
			
			ii. $NORD_{r2,k,h}^{c,t} = Min[RT\_QSOR_{r2,k,h}^{c,t}, Max(0, TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t})] + REAH_{r2,k,h}^{c,t} - RT\_QSOR_{r2,k,h}^{c,t}$
			
			iii. $NORD_{r3,k,h}^{c,t} = Min[RT\_QSOR_{r3,k,h}^{c,t}, Max(0, TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t} - RT\_QSOR_{r2,k,h}^{c,t})] + REAH_{r3,k,h}^{c,t} - RT\_QSOR_{r3,k,h}^{c,t}$							

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			c. $NORD_{r,k,h}^{s,t}$ for the steam turbine *resource* is calculated as: i. $NORD_{r1,k,h}^{s,t} = Min(RT\_QSOR_{r1,k,h}^{s,t}, TAOR\_CT_{k,h}^{s,t}) + REAH_{r1,k,h}^{s,t} - RT\_QSOR_{r1,k,h}^{s,t}$ ii. $NORD_{r2,k,h}^{s,t} = Min[RT\_QSOR_{r2,k,h}^{s,t}, Max(0, TAOR\_CT_{k,h}^{s,t} - RT\_QSOR_{r1,k,h}^{s,t})] + REAH_{r2,k,h}^{s,t} - RT\_QSOR_{r2,k,h}^{s,t}$ iii. $NORD_{r3,k,h}^{s,t} = Min[RT\_QSOR_{r3,k,h}^{s,t}, Max(0, TAOR\_CT_{k,h}^{s,t} - RT\_QSOR_{r1,k,h}^{s,t} - RT\_QSOR_{r2,k,h}^{s,t})] + REAH_{r3,k,h}^{s,t} - RT\_QSOR_{r3,k,h}^{s,t}$ d. $REAH_{r,k,h}^{c,t}$ for the combustion turbine *resource* is calculated as follows for each type of *class r reserve*: $REAH_{r,k,h}^{c,t} = TREAH_{r,k,h}^{M,t} \times \dfrac{EAH_{k,h}^{c,t}}{\sum^{M}(EAH_{k,h}^{c,t} + EAH_{k,h}^{s,t})}$ e. $REAH_{r,k,h}^{s,t}$ for the steam turbine *resource* is calculated as follows for each type of *class r reserve*: $REAH_{r,k,h}^{s,t} = TREAH_{r,k,h}^{M,t} \times \dfrac{EAH_{k,h}^{s,t}}{\sum^{M}(EAH_{k,h}^{c,t} + EAH_{k,h}^{s,t})}$ f. $EAH_{k,h}^{c,t} = Max(0, TAOR\_CT_{k,h}^{c,t} - \sum_{R} RT\_QSOR_{r,k,h}^{c,t})$ for the combustion turbine *resource* g. $EAH_{k,h}^{s,t} = Max(0, TAOR\_ST_{k,h}^{s,t} - \sum_{R} RT\_QSOR_{r,k,h}^{s,t})$ for the steam turbine *resource* h. When $\sum^{M}(EAH_{k,h}^{c,t} + EAH_{k,h}^{s,t})=0$, then $TREAH_{r,k,h}^{M,t}=0$, and when $\sum^{M}(EAH_{k,h}^{c,t} + EAH_{k,h}^{s,t})>0$, then i. $TREAH_{r1,k,h}^{M,t} = Min(\sum^{M}(EAH_{k,h}^{c,t} + EAH_{k,h}^{s,t}), (-1) \times \sum^{M}(ORIA_{r1,k,h}^{s,t} + ORIA_{r1,k,h}^{s,t}))$ ii. $TREAH_{r2,k,h}^{M,t} = Min[(\sum^{M}(EAH_{k,h}^{c,t} + EAH_{k,h}^{s,t})) - TREAH_{r1,k,h}^{M,t}, (-1) \times \sum^{M}(ORIA_{r2,k,h}^{c,t} + ORIA_{r2,k,h}^{s,t})]$ iii. $TREAH_{r3,k,h}^{M,t} = Min[(\sum^{M}(EAH_{k,h}^{c,t} + EAH_{k,h}^{s,t})) - TREAH_{r1,k,h}^{M,t} - TREAH_{r2,k,h}^{M,t}, (-1) \times \sum^{M}(ORIA_{r3,k,h}^{c,t} + ORIA_{r3,k,h}^{s,t})]$							
212 MRP new	Day-Ahead Market 10-Minute Spinning Reserve	MR Ch.9 s.3.1.10	$HORSA\{1\}_{k,h} = \sum^{M}(DAM\_PROR_{r1,h}^{m} \times DAM\_QSOR_{r1,k,h}^{m} + DAM\_PROR_{r1,h}^{i} \times DAM\_QSOR_{r1,k,h}^{i})$	Hourly	Due MP	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
	Settlement Credit (HORSA{1})									
213 MRP new	Real-Time 10-Minute Spinning Reserve Settlement Credit (HORSA{2})	MR Ch.9 s.3.1.11	$HORSA\{2\}_{k,h} = \sum^{M,T} \{RT\_PROR_{r1,h}^{m,t} \; x \; (RT\_QSOR_{r1,k,h}^{m,t} - DAM\_QSOR_{r1,k,h}^{m})$ $+ \; RT\_PROR_{r1,h}^{i,t} \; x \; (RT\_QSOR_{r1,k,h}^{i,t} - DAM\_QSOR_{r1,k,h}^{i})\}$	Interval	Either Way	13	N/A	N/A	N/A	
214 MRP new	Day-Ahead Market 10-Minute Non-Spinning Reserve Settlement Credit (HORSA{1})	MR Ch.9 s.3.1.10	$HORSA\{1\}_{k,h} = \sum^{M} (DAM\_PROR_{r2,h}^{m} \times DAM\_QSOR_{r2,k,h}^{m} + DAM\_PROR_{r2,h}^{i} \times DAM\_QSOR_{r2,k,h}^{i})$	Hourly	Due MP	13	13	13	13	
215 MRP new	Real-Time 10-Minute Non-Spinning Reserve Settlement Credit (HORSA{2})	MR Ch.9 s.3.1.11	$HORSA\{2\}_{k,h} = \sum^{M,T} \{RT\_PROR_{r2,h}^{m,t} \; x \; (RT\_QSOR_{r2,k,h}^{m,t} - DAM\_QSOR_{r2,k,h}^{m})$ $+ \; RT\_PROR_{r2,h}^{i,t} \; x \; (RT\_QSOR_{r2,k,h}^{i,t} - DAM\_QSOR_{r2,k,h}^{i})\}$	Interval	Either Way	13	13	13	13	
216 MRP new	Day-Ahead Market 30-Minute Operating Reserve	MR Ch.9 s.3.1.10	$HORSA\{1\}_{k,h} = \sum^{M} (DAM\_PROR_{r3,h}^{m} \times DAM\_QSOR_{r3,k,h}^{m} + DAM\_PROR_{r3,h}^{i} \times DAM\_QSOR_{r3,k,h}^{i})$	Hourly	Due MP	13	13	13	13	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
	Settlement Credit (HORSA{1})									
217 MRP new	Real-Time 30-Minute Operating Reserve Settlement Credit (HORSA{2})	MR Ch.9 s.3.1.11	$$HORSA\{2\}_{k,h} = \sum^{M,T} \{RT\_PROR_{r3,h}^{m,t}\ x\ (RT\_QSOR_{r3,k,h}^{m,t} - DAM\_QSOR_{r3,k,h}^{m}) \\ + RT\_PROR_{r3,h}^{i,t}\ x\ (RT\_QSOR_{r3,k,h}^{i,t} - DAM\_QSOR_{r3,k,h}^{i})\}$$	Interval	Either Way	13	13	13	13	
250 MRP updated + name change	10-Minute Spinning Reserve Hourly Uplift (HUSA)	MR Ch.9 s.3.11	**The set of *charge types* 'c' has been updated** $$= \sum_{C}^{M,T} TD_{k,h,c}\ x\ \left[\sum^{M,T}(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t} + RQ_{k,h}^{m,i,t})/\sum_{K}^{M,T}(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t})\right]$$ **Where:** a. C = the set of all *charge types* 'c' as follows: 206,212,213.	Hourly	Due *IESO*	13	N/A	0	13	
251	10 Minute Spinning Market Reserve Shortfall Debit (ORSSD$_{k,r,h}$)	MR Ch.9 s.3.9.2	Manual Entry as per MR Ch.9 s.3.9.2 where the value below which ORESF$_{k,r,h}^{m,t}$ shall be set at zero equals ∞.	Interval	Due *IESO*	13	13	N/A	N/A	
252 MRP updated + name change	10-Minute Non-Spinning Reserve Hourly Uplift	MR Ch.9 s.3.11	**The set of *charge types* 'c' has been updated** $$= \sum_{C}^{M,T} TD_{k,h,c}\ x\ \left[\sum^{M,T}(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t} + RQ_{k,h}^{m,i,t})/\sum_{K}^{M,T}(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t})\right]$$	Hourly	Due *IESO*	13	N/A	0	13	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
	(HUSA)		**Where:** a. C = the set of all *charge types* 'c' as follows: 208,214,215.							
253	10 Minute Non-spinning Market Reserve Shortfall Debit (ORSSD$_{k,r,h}$)	MR Ch.9 s.3.9.2	Manual Entry as per MR Ch.9 s.3.9.2 where the value below which ORESF$_{k,r,h}^{m,t}$ shall be set at zero equals ∞.	Interval	Due *IESO*	13	13	N/A	N/A	
254 MRP updated + name change	30 Minute Operating Reserve Hourly Uplift (HUSA)	MR Ch.9 s.3.11	****The set of *charge types* 'c' has been updated**** $$= \sum_{C}^{M,T} TD_{k,h,c} \; x \left[\sum^{M,T} \left(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t} + RQ_{k,h}^{m,i,t} \right) / \sum_{K}^{M,T} \left(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t} \right) \right]$$ **Where:** a. C = the set of all *charge types* 'c' as follows: 210,216,217.	Hourly	Due *IESO*	13	N/A	0	13	
255	30 Minute Operating Reserve Market Shortfall Debit (ORSSD$_{k,r,h}$)	MR Ch.9 s.3.9.2	Manual Entry as per MR Ch.9 s.3.9.2 where the value below which ORESF$_{k,r,h}^{m,t}$ shall be set at zero equals ∞.	Interval	Due *IESO*	13	13	N/A	N/A	
400	Black Start Capability Settlement Credit	MR Ch.9 s.4.2.2	Manual Entry as per MR Ch.9 s.4.2.2.	Monthly	Due MP	13	N/A	N/A	N/A	
404	Regulation Service	MR Ch.9 s.4.2.3	Manual Entry as per MR Ch.9 s.4.2.3.	Monthly	Due MP	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
	Settlement Credit									
410	IESO-Controlled Grid Special Operations Credit	MR Ch.5 s.8.2.6	Manual Entry as per MR Ch.5 s.8.2.6.	Monthly	Either way	13	N/A	N/A	N/A	
450	Black Start Capability Settlement Debit	MR Ch.9 s.4.2.2	$= \sum_{H,c}^{M,T} TD_{h,(400)} \times [(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}) / \sum_{k,H}^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t})]$ 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	
451	Hourly Reactive Support and Voltage Control Settlement Debit	MR Ch.9 s.4.2.4	$= \sum_{C}^{M,T} TD_{k,h,c} \times \left[\sum^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t} + RQ_{k,h}^{m,i,t}) / \sum_{K}^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}) \right]$ **Where:** a. C = the set of all *charge types* 'c' as follows: 1401,1402,1404,1405,1451.	Hourly	Due *IESO*	13	N/A	0	13	
452	Monthly Reactive Support and Voltage Control Settlement Debit	MR Ch.9 s.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. 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	
454	Regulation Service	MR Ch.9 s.4.2.3	$= \sum_{H,c}^{M,T} TD_{h,(404)} \times [(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}) / \sum_{k,H}^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t})]$	Monthly	Due *IESO*	13	N/A	0	13	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
	Settlement Debit		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'.							
460	IESO-Controlled Grid Special Operations Debit	MR Ch.5 s.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	MR Ch.9 s.4.2.1	Manual Entry as per MR Ch.9 s.4.2.1.	Monthly	Due MP	13	N/A	N/A	N/A	
550	Must Run Contract Settlement Debit	MR Ch.9 s.4.2.1	$= \sum_{H,c}^{M,T} TD_{h,(500)} \times [(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}) / \sum_{k,H}^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t})]$ 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	
600	Network Service Credit	MR Ch.9 s.4.1	$\sum_{k,H,c} (TD_{650})$ 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	MR Ch.9 s.4.1	$\sum_{k,H,c} (TD_{651})$	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	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			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.							
602	Transformation Connection Service Credit	MR Ch.9 s.4.1	$\sum_{k,H,c} (TD_{652})$ Where 'H' is the set of all *settlement hours* 'h' in the month during which the Transformation Connection Demand occurs at every *delivery point* defined for Transmission Transformation Connection Service charges.	Monthly	Due applicable *transmitters*	13	N/A	N/A	N/A	Subject to the OEB "Ontario Transmission Rate Order".
603	Export Transmission Service Credit	MR Ch.9 s.4.1	$\sum_{k,H,c} (TD_{653}^{i})$ 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	MR Ch.9 s.4.1	$NSD_{k,h}^{m}$ x 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 85% of the customer peak demand in any hour during the peak period.	Monthly	Due *IESO*	13	N/A	N/A	N/A	Subject to the OEB "Ontario Transmission Rate Order".
651	Line Connection Service Charge	MR Ch.9 s.4.1	$LCD_{k,h}^{m}$ x PTS-L	Monthly	Due *IESO*	13	N/A	N/A	N/A	Subject to the OEB "Ontario Transmission Rate Order".

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			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.							
652	Transformation Connection Service Charge	MR Ch.9 s.4.1	TCD$_{k,h}^m$ x 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	MR Ch.9 s.4.1	$\sum_H{}^T$ SQEW$_{k,h}^{i,t}$ x 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	MR. Ch.9 s.6.10.4	Manual Entry as per MR Ch.9 s.6.10.4.	Monthly	Due MP	13	13	0	13	Note: tax would follow original disputed transaction
703	Rural and Remote Settlement Credit	N/A	Manual Entry as per Regulation.	Monthly	Due MP	13	N/A	N/A	N/A	Ontario Regulation 442/01 Refer to Ministry of Energy website for details.
705	Ontario Fair Hydro Plan First Nations On-reserve Delivery Amount	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.

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
706	Ontario Fair Hydro Plan Distribution Rate Protection Amount	N/A	Manual entry based on: (1) the values submitted via on-line settlement form "Distribution Rate Protection (DRP)"	Monthly	Due LDCs either way	13	N/A	N/A	N/A	Eligibility, rates, and other implementation details subject to government and OEB regulations.
750	Dispute Resolution Balancing Amount (IESO)	MR. Ch.9 s.6.10.4	$\sum_K TD_{k,700}$, where applicable	Monthly	Due *IESO*	N/A	N/A	N/A	N/A	
751	Dispute Resolution Board Service Debit	MR. Ch.9 s.3.2.7	Manual entry as per 3.2.5-3.2.7	Monthly	Due *IESO*	13	13	13	13	
753	Rural and Remote Settlement Debit	N/A	$AQEW_{k,h}^{m,t} \times TP$	Monthly	Due *IESO*	13	N/A	N/A	N/A	Ontario Regulation 442/01 Refer to Ministry of Energy website for details.
755	MOE - Ontario Fair Hydro Plan First Nations On-reserve Delivery Balancing Amount	N/A	$\sum_K TD_{k,705}$ Where 'K' is the set of all *market participants* 'k'. Where $TD_{k,705}$ 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	$\sum_K TD_{k,706}$ Where 'K' is the set of all *market participants* 'k'. Where $TD_{k,706}$ 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.

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
850	Market Participant Default Settlement Debit (Recovery)	MR Ch.2 s.8.6	Manual Entry as per MR Ch.2 s.8.6.	Monthly	Due *IESO*	13	13	13	13	
851	Market Participant Default Interest Debit	MR Ch.2 ss.8.3 and 8.5	Manual Entry as per MR Ch.2 ss.8.3 and 8.5.	Monthly	Due *IESO*	N/A	N/A	N/A	N/A	
900	GST/HST Credit	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	$\sum_C TD_{k,c}$ 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.
1100 MRP new	Day-Ahead Market Energy Settlement Amount for Generators (HPTSA{1})	MR Ch.9 ss.3.1.2 and 3.1.3	$HPTSA\{1\}_{k,h} = \sum^{M} \left[\left(DAM\_QSI_{k,h}^{m} - DAM\_QSW_{k,h}^{m} \right) \times DAM\_LMP_{h}^{m} \right] + HPTSA\_PBC\{1\}_{k,h}$ **Where:** a. $HPTSA\_PBC\{1\}_{k,h} = \sum^{M} \left[DAM\_LMP_{h}^{m} \times \left(\sum_{S} DAM\_BCQ_{s,k,h}^{m} - \sum_{B} DAM\_BCQ_{k,b,h}^{m} \right) \right]$	Hourly	Due MP	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
1101 MRP updated + name change	Real-Time Energy Settlement Amount for Generators (HPTSA{2})	MR Ch.9 ss.3.1.5 and 3.1.6	**The following is effective on the commencement of *market transition*. Refer to section 3 for the version in effect prior to the commencement of *market transition*.** $$HPTSA\{2\}_{k,h} = \sum^{M,T} RT\_LMP_h^{m,t} \, x \, \frac{\left((AQEI_{k,h}^{m,t} - DAM\_QSI_{k,h}^m) - (AQEW_{k,h}^{m,t} - DAM\_QSW_{k,h}^m)\right)}{12} + HPTSA\_PBC\{2\}_{k,h}$$ **Where:** a. $HPTSA\{2\}\_PBC_{k,h} = \sum^{M,T} RT\_LMP_h^{m,t} \, x \left(\sum_s BCQ_{s,k,h}^{m,t} - \sum_B BCQ_{k,b,h}^{m,t}\right)$	Interval	Either Way	13	N/A	N/A	N/A	
1102 MRP new	Day-Ahead Market Energy Settlement Amount for Dispatchable Loads (HPTSA{1})	MR Ch.9 ss.3.1.2 and 3.1.3	$$HPTSA\{1\}_{k,h} = \sum^{M} \left[(DAM\_QSI_{k,h}^m - DAM\_QSW_{k,h}^m) \, x \, DAM\_LMP_h^m\right] + HPTSA\_PBC\{1\}_{k,h}$$ **Where:** a. $HPTSA\_PBC\{1\}_{k,h} = \sum^M \left[DAM\_LMP_h^m \, x \left(\sum_s DAM\_BCQ_{s,k,h}^m - \sum_B DAM\_BCQ_{k,b,h}^m\right)\right]$	Hourly	Due *IESO*	13	N/A	N/A	N/A	
1103 MRP updated	Real-Time Energy Settlement Amount for Dispatchable Loads	MR Ch.9 ss.3.1.5 and 3.1.6	**The following is effective on the commencement of *market transition*. Refer to section 3 for the version in effect prior to the commencement of *market transition*.**	Interval	Either Way	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
	(HPTSA{2})		$HPTSA\{2\}_{k,h} = \sum^{M,T} RT\_LMP_h^{m,t} \, x \, \dfrac{\left(\left(AQEI_{k,h}^{m,t} - DAM\_QSI_{k,h}^m\right) - \left(AQEW_{k,h}^{m,t} - DAM\_QSW_{k,h}^m\right)\right)}{12}$ $+ \; HPTSA\_PBC\{2\}_{k,h}$ **Where:** a. $HPTSA\{2\}\_PBC_{k,h} = \sum^{M,T} RT\_LMP_h^{m,t} \, x \left(\sum_S BCQ_{s,k,h}^{m,t} - \sum_B BCQ_{k,b,h}^{m,t}\right)$						
1104 MRP new	Day-Ahead Market Energy Settlement Amount for Price Responsive Loads (HPTSA{1})	MR Ch.9 ss.3.1.2 and 3.1.4	$HPTSA\{1\}\_PRL\_SSW_{k,h}$ $= -1 \, x \left[\sum^{M1}\left(DAM\_QSW_{k,h}^m \times DAM\_LMP_h^m\right) + \sum^{M2}\left(DAM\_QSW_{k,h}^m \times DAM\_LMP_h^m\right)\right]$ $+ \; HPTSA\_PBC\{1\}_{k,h}$ **Where:** a. $HPTSA\_PBC\{1\}_{k,h} = \sum^{M1}[DAM\_LMP_h^m \, x \, (\sum_S DAM\_BCQ_{s,k,h}^m - \sum_B DAM\_BCQ_{k,b,h}^m)]$ b. M1 = the set of all *delivery points* 'm' for *price responsive loads* and *self-scheduling electricity storage resources* that are registered to withdraw; and c. M2 = the set of all *delivery points* 'm' for *price responsive loads* associated with *load equipment* used as physical *hourly demand response resources* to fulfill *capacity obligations*.	Hourly	Due *IESO*	13	N/A	N/A	N/A	
1105 MRP new	Real-Time Energy Settlement Amount for Price Responsive Loads (HPTSA{2})	MR Ch.9 ss.3.1.5 and 3.1.7	$HPTSA\{2\}\_PRL\_SSW_{k,h}$ $= -1 \, x \left[\sum^{M1,T} RT\_LMP_h^{m,t} \, x \, \dfrac{\left(AQEW_{k,h}^{m,t} - DAM\_QSW_{k,h}^m\right)}{12}\right.$ $\left. - \sum^{M2,T} RT\_LMP_h^{m,t} \, x \, \dfrac{DAM\_QSW_{k,h}^m}{12}\right] + HPTSA\_PBC\{2\}_{k,h}$ **Where:** a. $HPTSA\{2\}\_PBC_{k,h} = \sum^{M,T} RT\_LMP_h^{m,t} \, x \, (\sum_S BCQ_{s,k,h}^{m,t} - \sum_B BCQ_{k,b,h}^{m,t})$ b. M1 = the set of all *delivery points* 'm' for *price responsive loads* and *self-scheduling electricity storage resources* that are registered to withdraw; and	Interval	Either Way	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			c. M2 = the set of all *delivery points* 'm' for *price responsive loads* associated with *load equipment* used as physical *hourly demand response resources* to fulfill *capacity obligations*.							
1106 MRP new	Day-Ahead Market Energy Settlement Amount for Virtual Transactions to Sell (HVTSA{1})	MR Ch.9 s.3.1.8	$$HVTSA\{1\}_{k,h} = \sum^{v} DAM\_QVSI^{v}_{k,h} \times DAM\_LMP^{vz}_{h}$$	Hourly	Due MP	N/A	N/A	N/A	N/A	
1107 MRP new	Real-Time Energy Settlement Amount for Virtual Transactions to Sell (HVTSA{2})	MR Ch.9 s.3.1.9	$$HVTSA\{2\}_{k,h} = -1 \times \sum^{v,T} DAM\_QVSI^{v}_{k,h} / 12 \times RT\_LMP^{vz,t}_{h}$$	Interval	Due *IESO*	N/A	N/A	N/A	N/A	
1108 MRP new	Day-Ahead Market Energy Settlement Amount for Virtual Transactions to Buy (HVTSA{1})	MR Ch.9 s.3.1.8	$$HVTSA\{1\}_{k,h} = -1 \times \sum^{v} DAM\_QVSW^{v}_{k,h} \times DAM\_LMP^{vz}_{h}$$	Hourly	Due *IESO*	N/A	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
1109 MRP new	Real-Time Energy Settlement Amount for Virtual Transactions to Buy (HVTSA{2})	MR Ch.9 s.3.1.9	$HVTSA\{2\}_{k,h} = \sum^{V,T} DAM\_QVSW^{v}_{k,h} / 12 \; x \; RT\_LMP^{vz,t}_{h}$	Interval	Due MP	N/A	N/A	N/A	N/A	
1110 MRP new	Day-Ahead Market Energy Settlement Amount for Imports (HPTSA{1})	MR Ch.9 ss.3.1.2 and 3.1.3	$HPTSA\{1\}_{k,h} = \sum^{M} \left[\left(DAM\_QSI^{i}_{k,h} - DAM\_QSW^{i}_{k,h} \right) x \; DAM\_LMP^{i}_{h} \right] + HPTSA\_PBC\{1\}_{k,h}$ **Where:** a. $HPTSA\_PBC\{1\}_{k,h} = \sum^{M} \left[DAM\_LMP^{i}_{h} \; x \left(\sum_{S} DAM\_BCQ^{i}_{s,k,h} - \sum_{B} DAM\_BCQ^{i}_{k,b,h} \right) \right]$	Hourly	Due MP	N/A	13	N/A	N/A	
1111 MRP updated	Real-Time Energy Settlement Amount for Imports (HPTSA{2})	MR Ch.9 ss.3.1.5 and 3.1.6	****The following is effective on the commencement of *market transition*. Refer to section 3 for the version in effect prior to the commencement of *market transition*.**** $HPTSA\{2\}_{k,h} = \sum^{M,T} RT\_LMP^{i,t}_{h} \; x \; \dfrac{\left(\left(SQEI^{i,t}_{k,h} - DAM\_QSI^{i}_{k,h} \right) - \left(SQEW^{i,t}_{k,h} - DAM\_QSW^{i}_{k,h} \right) \right)}{12}$ $+ \; HPTSA\_PBC\{2\}_{k,h}$ **Where:** a. $HPTSA\{2\}\_PBC_{k,h} = \sum^{M,T} RT\_LMP^{i,t}_{h} \; x \left(\sum_{S} BCQ^{i,t}_{s,k,h} - \sum_{B} BCQ^{i,t}_{k,b,h} \right)$	Interval	Either Way	N/A	13	N/A	N/A	
1112 MRP new	Day-Ahead Market Energy Settlement	MR Ch.9 ss.3.1.2 and 3.1.3		Hourly	Due *IESO*	N/A	N/A	0	13	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
	Amount for Exports (HPTSA{1})		$HPTSA\{1\}_{k,h} = \sum^{M}\left[\left(DAM\_QSI^{i}_{k,h} - DAM\_QSW^{i}_{k,h}\right) x\ DAM\_LMP^{i}_{h}\right] + HPTSA\_PBC\{1\}_{k,h}$ **Where:** a. $HPTSA\_PBC\{1\}_{k,h} = \sum^{M}\left[DAM\_LMP^{i}_{h} x \left(\sum_{S} DAM\_BCQ^{i}_{s,k,h} - \sum_{B} DAM\_BCQ^{i}_{k,b,h}\right)\right]$							
1113 MRP updated	Real-Time Energy Settlement Amount for Exports (HPTSA{2})	MR Ch.9 ss.3.1.5 and 3.1.6	****The following is effective on the commencement of _market transition_. Refer to section 3 for the version in effect prior to the commencement of _market transition_.**** $HPTSA\{2\}_{k,h} = \sum^{M,T} RT\_LMP^{i,t}_{h} x \dfrac{\left(\left(SQEI^{i,t}_{k,h} - DAM\_QSI^{i}_{k,h}\right) - \left(SQEW^{i,t}_{k,h} - DAM\_QSW^{i}_{k,h}\right)\right)}{12} + HPTSA\_PBC\{2\}_{k,h}$ **Where:** a. $HPTSA\{2\}\_PBC_{k,h} = \sum^{M,T} RT\_LMP^{i,t}_{h} x \left(\sum_{S} BCQ^{i,t}_{s,k,h} - \sum_{B} BCQ^{i,t}_{k,b,h}\right)$	Interval	Either Way	N/A	N/A	0	13	
1115 MRP updated + name change	Non-Dispatchable Load Energy Settlement Amount (HPTSA_NDL)	MR Ch.9 ss.3.1.5 and 3.2	****The following is effective on the commencement of _market transition_. Refer to section 3 for the version in effect prior to the commencement of _market transition_.**** $HPTSA\_NDL_{k,h} = -1 x \left(DAM\_LMP^{z}_{h} + LFDA_{h}\right) x \sum^{T}\left(AQEW^{m,t}_{k,h} - AQEI^{m,t}_{k,h}\right) + HPTSA\_PBC\{2\}_{k,h}$ **Where:** a. $HPTSA\{2\}\_PBC_{k,h} = \sum^{M,T} DAM\_LMP^{z}_{h} x \left(\sum_{S} BCQ^{m,t}_{s,k,h} - \sum_{B} BCQ^{m,t}_{k,b,h}\right)$ b. $LFDA_{h} = \dfrac{Real\_Time\ Purchase\ Cost\_Benefit_{h} + DAM\ Volume\ Factor\ Cost\_Benefit_{h}}{\sum^{M,T}_{K,h}\left(AQEW - AQEI\right)^{m,t}_{k,h}}$ **and where:**	Hourly	Due _IESO_	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			a. M2 = the set of all *hourly demand response resources* 'd' that are not associated with *load equipment* registered as *price responsive loads*; b. *Real_Time Purchase Cost_Benefit* $$= \sum_{K,h}^{M,T} \left[RT\_LMP_h^{m,t} \; x \; (AQEW_{k,h}^{m,t} - AQEI_{k,h}^{m,t} - DAM\_QSW_{k,h}^m)/12 \right]$$ $$- \sum_{K,h}^{M2,T} \left[RT\_LMP_h^{d,t} \; x \; DAM\_QSW_{k,h}^d/12 \right]$$ c. *DAM Volume Factor Cost_Benefit* $$= DAM\_LMP_h^z \; x \left[\sum_{K,h}^{M,T} (DAM\_QSW_{k,h}^m - AQEW_{k,h}^{m,t} + AQEI_{k,h}^{m,t})/12 \right. $$ $$\left. + \sum_{K}^{M2} \left[DAM\_LMP_h^z \; x \; DAM\_QSW_{k,h}^d \right] \right]$$							
1116 MRP new	Internal Congestion and Loss Residual (ICLR)	MR Ch.9 s.4.7	$$ICLR_k = CRLR \; \times \sum_H^{M,T} AQEW_{k,h}^{m,t} \Big/ \sum_{K,H}^{M,T} AQEW_{k,h}^{m,t}$$	Monthly	Either Way	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			Where: $$CRLR = \sum_{K,H}^{M0} \left[(DAM\_QSW_{k,h}^{m} - DAM\_QSI_{k,h}^{m}) \, x \, DAM\_LMP_{h}^{m} \right.$$ $$+ \sum^{T} \left((AQEW_{k,h}^{m,t} - AQEI_{k,h}^{m,t}) - (DAM\_QSW_{k,h}^{m} - DAM\_QSI_{k,h}^{m}) \right) x \, RT\_LMP_{h}^{m,t}/12 \right]$$ $$+ \sum_{K,H}^{V} \left[(DAM\_QVSW_{k,h}^{v} - DAM\_QVSI_{k,h}^{v}) \, x \sum^{T} (DAM\_LMP_{h}^{vz} - RT\_LMP_{h}^{vz,t}) \right]$$ $$+ \sum_{K,H}^{M1} \left[(DAM\_LMP_{h}^{z} + LFDC_{h}) \, x \sum^{T} AQEW_{k,h}^{m,t} \right]$$ $$+ \sum_{K,H}^{I} \left[(DAM\_QSW_{k,h}^{i} - DAM\_QSI_{k,h}^{i}) \, x \, DAM\_LMP_{h}^{i} \right.$$ $$+ \sum^{T} \left((SQEW_{k,h}^{i,t} - SQEI_{k,h}^{i,t}) - (DAM\_QSW_{k,h}^{i} - DAM\_QSI_{k,h}^{i}) \right) x \, RT\_LMP_{h}^{i,t}/12 \right]$$ $$- \sum_{K,H}^{I} (DAM\_QSW_{k,h}^{i} - DAM\_QSI_{k,h}^{i}) \, x \, DAM\_PEC_{h}^{i}$$ $$- \sum_{K,H}^{I} (DAM\_QSW_{k,h}^{i} - DAM\_QSI_{k,h}^{i}) \, x \, DAM\_PNISL_{h}^{i}$$ $$- \sum_{K,H}^{I,T} \left((SQEW_{k,h}^{i,t} - SQEI_{k,h}^{i,t}) - (DAM\_QSW_{k,h}^{i} - DAM\_QSI_{k,h}^{i}) \right) \times RT\_PEC_{h}^{i,t}/12$$ $$- \sum_{K,H}^{I,T} \left((SQEW_{k,h}^{i,t} - SQEI_{k,h}^{i,t}) - (DAM\_QSW_{k,h}^{i} - DAM\_QSI_{k,h}^{i}) \right) \times RT\_PNISL_{h}^{i,t}/12$$ **and where:** a. H = the set of all *settlement hours* 'h' in the current *energy market billing period*; b. M1 = the set of all *delivery points* 'm' for *non-dispatchable loads*; and c. M0 = the set of all *delivery points* 'm' except those for *non-dispatchable loads*.						
1117 MRP new	Day-Ahead Market Net External Congestion Residual (DAM_NECR)	MR Ch.9 s.3.8.2	$$DAM\_NECR_h = \sum_{K}^{I} \left[(DAM\_QSW_{k,h}^{i} - DAM\_QSI_{k,h}^{i}) \, x \, DAM\_PEC_{h}^{i} \right] - \sum_{K} \left[TRSC_{k,h} \right]$$ **Where:** a. $TRSC_{k,h}$ = the *transmission rights settlement* credit *settlement amount* calculated for *charge type* 104 in accordance with MR Ch.9 s.3.8.1.	Hourly	Accumulates in the *TR Clearing Account*	N/A	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
1118 MRP new	Real-Time External Congestion Residual Uplift (RT_ECRU)	MR Ch.9 ss.4.8.1-4.8.4	**For loads:** $$RT\_ECRU_k = RT\_ECR_L \times \sum_H^{M,T} AQEW_{k,h}^{m,t} / \sum_{K,H}^{M,T} AQEW_{k,h}^{m,t}$$ **For exporters:** $$RT\_ECRU_k = RT\_ECR_E \times \sum_H^{I,T} SQEW_{k,h}^{i,t} / \sum_{K,H}^{I,T} SQEW_{k,h}^{i,t}$$ **Where:** a. $RT\_ECR_L = RT\_ECR \times \sum_K TD_C / \sum_K TD_{C,C1}$ b. $RT\_ECR_E = RT\_ECR \times \sum_K TD_{C1} / \sum_K TD_{C,C1}$ c. $RT\_ECR = \sum_{K,H}^{I,T} \left((SQEW_{k,h}^{i,t} - SQEI_{k,h}^{i,t}) - (DAM\_QSW_{k,h}^i - DAM\_QSI_{k,h}^i) \right) \times RT\_PEC_h^{i,t}/12$ d. H = the set of all *settlement hours* 'h' in the current *energy market billing period*; e. TD_C = the total dollar value of monthly service *charge type* 'C' in the current *energy market billing period*; f. $TD_{C,C1}$ = the total dollar value of monthly service *charge type* 'C' and 'C1' in the current *energy market billing period*; g. TD_{C1} = the total dollar value of monthly service *charge type* 'C1' in the current *energy market billing period*; h. C = the set of all monthly provincial *transmission services charge charge types* in the current *energy market billing period* as follows: 650,651,652; i. C1 = the set of all monthly export *transmission services charge charge types* in the current *energy market billing period* as follows: 653; and j. T = the set of all *metering intervals* 't' in the set of all *settlement hours* 'H'.	Monthly	Either Way	13	N/A	0	13	
1119 MRP new	Day-Ahead Market Net Interchange Scheduling Limit Residual Uplift (DAM_NISLRU)	MR Ch.9 ss.4.8.5-4.8.7	$$DAM\_NISLU_k = DAM\_NISLR \times \left[\sum_H^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}) / \sum_{K,H}^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}) \right]$$ **Where:** a. $DAM\_NISLR = \sum_{K,H}^{I} \left[(DAM\_QSW_{k,h}^i - DAM\_QSI_{k,h}^i) \times DAM\_PNISL_h^i \right]$	Daily	Either Way	13	N/A	0	13	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
1120 MRP new	Real-Time Net Interchange Scheduling Limit Residual Uplift (RT_NISLRU)	MR Ch.9 ss.3.11 and 4.8.8	$RT\_NISLRU_h = RT\_NISLR_h \: x \: \left[\sum^{M,T} \left(AQEW^{m,t}_{k,h} + SQEW^{i,t}_{k,h} + RQ^{m,i,t}_{k,h} \right) / \sum^{M,T}_{K} \left(AQEW^{m,t}_{k,h} + SQEW^{i,t}_{k,h} \right) \right]$ **Where:** a. $RT\_NISLR_h = \sum^{I,T}_{K} \left(\left(SQEW^{i,t}_{k,h} - SQEI^{i,t}_{k,h} \right) - \left(DAM\_QSW^{i}_{k,h} - DAM\_QSI^{i}_{k,h} \right) \right) \times RT\_PNISL^{i,t}_h / 12$	Hourly	Either Way	13	N/A	0	13	
1138 MRP name change	Fuel Cost Compensation Credit (FCC)	MR Ch.9 s.4.11	Manual entry based on values submitted by *market participants* with *GOG-eligible resources* via Online settlement form "Fuel Cost Compensation", subject to MR Ch.9 s.4.11.	Hourly	Due MP	13	N/A	N/A	N/A	
1148	GA Energy Storage Injection Reimbursement	N/A	$U_k \: x \: GAR_B$	Monthly	Due MP	13	N/A	N/A	N/A	Eligibility and other implementation details subject to government regulation.
1188 MRP name change	Fuel Cost Compensation Credit Uplift (FCCU)	MR Ch.9 s.4.14.8	$FCCU_k = -1 \: x \sum^{M}_{K} FCC^{m}_k \: x \sum^{M,T}_{H} \left(AQEW^{m,t}_{k,h} + SQEW^{i,t}_{k,h} \right) / \sum^{M,T}_{K,H} \left(AQEW^{m,t}_{k,h} + SQEW^{i,t}_{k,h} \right)$ **Where:** a. FCC^{m}_k = the fuel cost compensation *settlement amount* calculated for *charge type* 1138 in accordance with MR Ch.9 s.4.11 for *market participant* 'k' at *delivery point* 'm'; and b. H = the set of all *settlement hours* 'h' in the *energy market billing period*.	Monthly	Due *IESO*	13	N/A	0	13	
1314	Capacity Obligation – Availability Payment	MR Ch.9 s.4.13.1	$CAAP^{m}_k = \sum^{H} CCO^{m}_{k,h} \: x \: CACP^{z}_h$	Monthly	Due MP	13	13	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
	(CAAP)		**Where:** a. H = the set of all *settlement hours* 'h' within the *availability window* of all *business days* in the relevant *energy market billing period*.							
1315 MRP updated	Capacity Obligation – Availability Charge (CAAC)	MR Ch.9 s.4.13.2	****The following is effective on the commencement of *market transition*. Refer to section 3 for the version in effect prior to the commencement of *market transition*.**** In regards to a *capacity market participant* participating with an *hourly demand response resource* or a *capacity dispatchable load resource*: $$CAAC_k^m = \sum^H (-1) \; x \; Max\,(0, CCO_{k,h}^m - DREBQ_{k,h}^m) \; x \; CACP_h^z \; x \; CNPF_{tm}$$ **Where:** a. H = the set of all *settlement hours* 'h' 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 market* or failed to maintain such *energy bid* through the *real-time market*, $DREBQ_{k,h}^m = 0$; c. In regards to *hourly demand response resource*, if the *demand response energy bids* submitted for *settlement hour* 'h' in either the *day-ahead market* or the *real-time market* does not form part of *energy bids* spanning at least four consecutive *settlement hours* during the relevant *availability window*, $DREBQ_{k,h}^m = 0$; d. If the *demand response energy bid* submitted in the *day-ahead market* for *settlement hour* 'h' is not equal to the *demand response energy bid* submitted in the *real-time market* for the same *settlement hour*, $DREBQ_{k,h}^m$ shall be equal to the lesser of the two *demand response energy bids*; and e. Notwithstanding any of the foregoing, $DREBQ_{k,h}^m$ shall not exceed the $CARC_k^m$ 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*: $$CAAC_k^m = \sum^H (-1) \; x \; Max\,(0, CCO_{k,h}^m - CAEO_{k,h}^m) \; x \; CACP_h^z \; x \; CNPF_{tm}$$ **Where:** a. H = the set of all *settlement hours* 'h' within the *availability window* during the relevant *trading day*;	Daily	Due *IESO*	13	13	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			b. If the *capacity market participant* did not submit an *energy offer* in the *day-ahead market* or failed to maintain such *energy offer* in accordance with the applicable *market manual* for *settlement hour* 'h', $CAEO_{k,h}^m = 0$; c. If the *energy offer* submitted in the *day-ahead market* for *settlement hour* 'h' is not equal to the *energy offer* submitted in the *pre-dispatch process* for the same *settlement hour*, $CAEO_{k,h}^m$ shall be equal to the lesser of the two *energy offers*; and d. If a *capacity storage resource* receives a non-zero *energy dispatch instruction* within the relevant *availability window*, the $CAEO_{k,h}^m$ 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)	MR Ch.9 s.4.13.4	$CAADM_k^m = (-1) \ x \ CAAP_k^m$ **Where:** a. $CAAP_k^m$ = the *capacity obligation* availability payment *settlement amount,* calculated in accordance with MR Ch.9 s.4.13.1, 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)	MR Ch.9 s.4.13.3	$CADC_{k,h}^m = (-1) \ x \ DRSQty_{k,h}^m \ x \ CACP_h^z \ x \ CNPF_{tm}$ **Where:** a. h = 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*.	Hourly	Due *IESO*	13	13	N/A	N/A	
1318	Capacity Obligation – Capacity Charge (CACC)	MR Ch.9 s.4.13.5	$CACC_k^m = (-1) \ x \ CAAP_k^m$ **Where:** a. $CAAP_k^m$ = the *capacity obligation* availability payment *settlement amount,* calculated in accordance with MR Ch.9 s.4.13.1, 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	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
1319	Capacity Obligation – Buy-Out Charge	MR Ch.9 s.4.13.9	$CABOC_k^m = (-1) \times 33\% \times \sum^H CBOC_k^m \times CACP_h^z \times CNPF_{tm}$ **Where:** a. H = the set of all *settlement hours* 'h' within the *availability window* of all *trading days* from the buy-out effective date to the end of the *commitment period*.	Monthly	Due *IESO*	13	13	N/A	N/A	

1320 MRP updated	Capacity Obligation – Dispatch Test Payment and Emergency Activation Payment	MR Ch.9 s.4.13.11	****The following is effective on the commencement of *market transition*. Refer to section 3 for the version in effect prior to the commencement of *market transition*.****
			
			For *capacity obligation dispatch test* activations
			
			$CATAP_{k,h}^m = HDRTAPR \; x \; HDRDC_{k,h}^m$
			
			For *capacity obligation emergency operating state* activations
			
			a. For *hourly demand response resource* that is not associated with *load equipment* registered as a *price responsive load*
			
			$CAEOP_{k,h}^m = Max(0, HDRBP_{k,h}^m - Max(0, DAM\_LMP_h^z + LFDA_h)) \; x \; HDRDC_{k,h}^m$
			
			   Where:
			   i. $LFDA_h$ = the load forecast deviation adjustment for *settlement hour* 'h' determined in accordance with MR Ch.9 s.3.2.3.
			
			b. For *hourly demand response resource* that is associated with *load equipment* registered as a *price responsive load*
			
			$CAEOP_{k,h}^m = Max(0, HDRBP_{k,h}^m - Max(0, RT\_LMP_h^z)) \; x \; HDRDC_{k,h}^m$
				Hourly	Due MP	13	13	N/A	N/A	

1321	Capacity Obligation – Capacity Import	MR Ch.9 s.4.13.6	$CACIF_k^m = (-1) \; x \; CAAP_k^m$	Monthly	Due *IESO*	N/A	13	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
	Call Failure Charge (CACIF)		**Where:** a. $CAAP_k^m$ = the *capacity obligation* availability payment *settlement amount*, calculated in accordance with MR Ch.9 s.4.13.1, 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)	MR Ch.9 s.4.13.7	$$CACD_k^i = \sum^H (-1.5) \; x \; OCMW_k^i \; x \; CACP_h^z$$ **Where:** a. H = the set of all *settlement hours* 'h' 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)	MR Ch.9 s.4.13.8	$$CAIPA_k^m = \left(-1 \; x \; Max(0, \left(CAAP_k^m \; x \; (UCAP \; Adjustment) + \sum^H CAAC_{k,h}^m \right) \right)$$ **Where:** a. $CAAP_k^m$ = the *capacity obligation* availability payment *settlement amount* for *capacity market participant* 'k' at *delivery point* 'm' for the relevant *energy market billing period*, calculated pursuant to MR Ch.9 s.4.13.1; b. $CAAC_{k,h}^m$ = the *capacity obligation* availability charge *settlement amount* for *capacity market participant* 'k' at *delivery point* 'm' for *settlement hour* 'h', as calculated pursuant to MR Ch.9 s.14.13.2; c. H = the set of all *settlement hours* 'h' within the *availability window* of the relevant *energy market billing period*; and d. UCAP Adjustment = 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 MR Ch.9 s.6.8, and but for filing such *notice of disagreement* the *capacity market participant* would have forfeited any of its *capacity obligation* pursuant to MR Ch.7 s.19.4.18, then the UCAP Adjustment shall equal 100%.	Monthly	Due *IESO*	13	N/A	N/A	N/A	
1324	Capacity Obligation – Availability	MR Ch.9 s.4.13.12	$$CAACT_k^m = \left(Min\left((-1) \; x \; \sum^{TM} \left(\left(\sum^D CAAC_k^m\right) + UCAP \; Adjustment \; x \; CAAP_k^m + CAIPA_k^m\right),\right.\right.$$ $$\left.\left.\sum^H Max\left(0, \left(RAC_k - CCO_{k,h}\right) \; x \; CACP_h \; x \; CNPF_{tm}\right)\right)\right)$$		Due MP	13	13	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
	Charge True-up Payment (CAACT)		**Where:** a. $CAAC_k^m$ = the *capacity obligation* availability charge *settlement amount* for *capacity market participant* 'k' at *delivery point* or *intertie metering 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 MR Ch.9 s.14.13.2.1; b. UCAP Adjustment = a de-rate (in %) determined in accordance with MR Ch.9 s.4.13.8; c. $CAAP_k^m$ = 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 MR Ch.9 s.4.13.1; d. $CAIPA_k^m$ = 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 MR Ch.9 s.4.13.8; e. D = the set of all *trading days* within the relevant *energy market billing period*; f. TM = the set of all *energy market billing periods* within the relevant *obligation period*; and g. H = 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)
		MR Ch.9 s.4.13.13	$$CACT_k^m = -1 \; x \; Min\left(0, \left(\sum_H TD_{C,k,h}^m + \sum_H TD_{P,k,h}^m\right)\right)$$
			Where:
			a. $TD_{C,k,h}^m$ = 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:
			   i. 'C' is the set of the *settlement amounts* applied in accordance with MR Ch.9 ss. 4.13.2, 4.13.2.1, 4.13.4, 4.13.5, 4.13.6, 4.13.7 and 4.13.8.
			b. $TD_{P,k,h}^m$ = 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:
			   i. 'P' is the set of the *settlement amounts* applied in accordance with MR Ch.9 ss. 4.13.1 and 4.13.12.
			c. H = the set of all *settlement hours* 'h' within the *availability window* of the relevant *obligation period*.
					Due MP	13	13	N/A	N/A	

1350	Capacity Based Recovery Amount for Class A Loads	MR Ch.9 s.4.13.14	$$CAU_k^m = \sum_{H,M}\left(TD_{C,k,h}^m \; x \; PDF_k\right)$$	Monthly	Due *IESO*	13	N/A	N/A	N/A	Refer to comments under *charge type* 147

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
	(CAU)		**Where:** a. H = the set of all *settlement hours* 'h' in the relevant *energy market billing period*; b. M = the set of all *delivery points* 'm' of *market participant* 'k'; c. $TD_{C,k,h}^m$ = 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 *energy market billing period,* where i. 'C' is the set of the *settlement amounts* applied in accordance with MR Ch.9 ss. 4.13.1, 4.13.2, 4.13.9, 4.13.11, 4.13.12, and 4.13.13; and d. PDF_k = 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.						
1351	Capacity Based Recovery Amount for Class B Loads (CAU)	MR Ch.9 s.4.13.14.2	**For Fort Frances Power Corporation Distribution Inc.:** $CAU_k^m = (\Sigma_{H,M} TD_{C,k,h^m} - TD_{C1350,k,h^m}) \times Max((\Sigma_H{}^{M,T} AQEW_{k,h}{}^{m,t} + EGEI_k - EEQ),0)$ / Class B Load **Where:** a. $TD_{C,k,h}{}^m$ = 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. 4.13.1, 4.13.2, 4.13.9, 4.13.11, 4.13.12, and 4.13.13; b. $TD_{C1350,k,h}{}^m$ = total dollar value of *settlement amounts* applied pursuant to section 4.13.14.1 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 Participants and Distributors:** CAU_k^m $= (\Sigma_{H,M} TD_{C,k,h^m} - TD_{C1350,k,h^m})$ $\times Max\left((\Sigma_H{}^{M,T} AQEW_{k,h}{}^{m,t} + EGEI_k - GA\_AQEW_{g,k,h,M}{}^{m,t} - PGS_{h,M}),0\right)$ / Class B Load **Where:** a. $TD_{C,k,h}{}^m$ = 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. 4.13.1, 4.13.2, 4.13.9, 4.13.11, 4.13.12 and 4.13.13.	Monthly	Due *IESO*	13	N/A	N/A	N/A	Refer to comments under *charge type 148*

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			b. $\text{TD}_{\text{C1350},k,h}{}^{m}$ = total dollar value of *settlement amounts* applied pursuant to MR Ch.9 s.4.13.14.1for *capacity market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' in the relevant *energy market billing period*; c. Class B load is calculated as follows: $$(\Sigma_K(\text{MAX}(\Sigma_H{}^{\text{M,T}}\text{AQEW}_{k,h}{}^{m,t}+\text{EGEI}_k-\text{EEQ}-\Sigma_H{}^{\text{M,T}}\text{GA\_AQEW}_{g,k,h,M}{}^{m,t}-\Sigma_H\text{PGS}_{h,M},0)))-\Sigma_K U_k$$ **Where:** i. H = the set of all *settlement hours* 'h' in the relevant *energy market billing period*. ii. M = the set of all *delivery points* 'm' of *market participant* 'k'. iii. C = the set of the following *charge types* 'c': 1314 to 1320, 1321, 1322.							
1400	OPA Contract Adjustment Settlement Amount	N/A	Manual entry based on the values submitted by the former *OPA* via On-line settlement form "Global Adjustment Amount Information", subject to Regulation.	Monthly	Due *IESO*	13	N/A	N/A	N/A	Implementation details subject to government regulation
1401	Incremental Loss Settlement Credit	MR Ch.9 s.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	MR Ch.9 s.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	MR Ch.9 s.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	MR Ch.9 s.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

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
	Settlement Credit									
1405	Hourly Condense Energy Costs Settlement Credit	MR Ch.9 s.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	MR Ch.9 s.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
1407	Condense Transmission Tariff Reimbursement Settlement Credit	MR Ch.9 s.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	MR Ch.9 s.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	MR Ch.9 s.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	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	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
	Settlement Amount									
1412	Feed-In Tariff Program Settlement Amount	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 Amount Settlement Credit	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	Manual entry based on the values submitted by the *market participant*.	Monthly	Due LDCs Either way	13	N/A	N/A	N/A	
1416	Conservation and Demand Management – Compensation Settlement Credit	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	MR Ch.9 s.4.2.4	Calculated as per *ancillary service* contracts.	Daily	Due MP	13	N/A	N/A	N/A	Reactive Support and Voltage Control Service
1418	Biomass Non-Utility Generation Contracts	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	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
	Settlement Amount									
1419	Energy from Waste (EFW) Contracts Settlement Amount	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	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
1425	Hydroelectric Standard Offer Program Settlement Amount	N/A	Manual Entry.	Monthly	Due LDCs either way	13	N/A	N/A	N/A	
1427	Renewables Funding Amount	N/A	Manual entry as per Ontario Transfer Payment Agreement.	Monthly	Due IESO	13	N/A	N/A	N/A	Ontario Regulation 735/20
1428	Small Hydro Program Settlement Amount	N/A	Manuel Entry.	Monthly	Due LDCs either way	13	N/A	N/A	N/A	November 1, 2024
1429	Pre-Development Costs Settlement Amount	N/A	Manual entry as per Ontario Transfer Payment Agreement.	Monthly	Due IESO	0	N/A	N/A	N/A	May 1, 2025
1450	OPA Contract Adjustment	N/A	TD_{1400}	Monthly	Due IESO	0	N/A	N/A	N/A	Implementation details subject to

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
	Balancing Amount									government regulation
1451	Incremental Loss Offset Settlement Amount	MR Ch.9 s.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	$\Sigma_K TD_{k,9983}$ 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	$\Sigma_K TD_{k,1410}$ Where 'K' is the set of all market participants 'k'. Where TDk,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	
1462	Feed-In Tariff Balancing Amount	N/A	$\Sigma_K TD_{k,1412}$ Where 'K' is the set of all market participants 'k'. Where TDk,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 Amount Settlement Debit	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 TDk,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	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
1464	Hydroelectric Contract Initiative Balancing Amount	N/A	$\Sigma_K TD_{k,1414}$ Where 'K' is the set of all market participants 'k'. Where $TD_{k,1414}$ 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	
1466	Conservation and Demand Management – Compensation Balancing Amount	N/A	$\Sigma_K TD_{k,1416}$ Where 'K' is the set of all market participants 'k'. Where $TD_{k,1416}$ 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) Balancing Amount	N/A	$\Sigma_K TD_{k,9982}$ Where 'K' is the set of all market participants 'k'. Where $TD_{k,9982}$ is the settlement amount of charge type 9982 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
1468	Biomass Non-Utility Generation Contracts Balancing Amount	N/A	$\Sigma_K TD_{k,1418}$ Where 'K' is the set of all market participants 'k'. Where $TD_{k,1418}$ 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	$\Sigma_K TD_{k,1419}$ 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	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			Where TDk,1419 is the total settlement amount of charge type 1419 for the month for market participant 'k'.							
1475	Hydroelectric Standard Offer Program Balancing Amount	N/A	$\Sigma_K TD_{k,1425}$ 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	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
1478	Small Hydro Program Balancing Amount	N/A	$\Sigma KTD_{k,1428}$ Where 'K' is the set of all market participants 'k'. Where TDk,1428 is the total settlement amount of charge type 1428 for the month for market participant 'k'.	Monthly	Due IESO	0	N/A	N/A	N/A	
1479	Pre-Development Costs Settlement Balancing Amount	N/A	TD_{1429}	Monthly	Due IESO	0	N/A	N/A	N/A	May 1, 2025
1487	Non-Hydro Renewables Funding Balancing Amount	N/A	TD_{1427}	Monthly	Due IESO	13	N/A	N/A	N/A	Ontario Regulation 735/20

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
1600	Forecasting Service Settlement Amount	MR Ch.9 s.4.12	Manual entry based on the values submitted by the forecasting entity.	Monthly	Due MP	13	N/A	N/A	N/A	
1650	Forecasting Service Balancing Amount	MR Ch.9 ss.4.12 and 4.14.12	$= \sum_{H,C}{}^{M,T} TD_{h,c} \times [(AQEW_{k,h}{}^{m,t} + SQEW_{k,h}{}^{i,t}) / \sum_{k,H}{}^{M,T} (AQEW_{k,h}{}^{m,t} + SQEW_{k,h}{}^{i,t})]$ 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)	MR. Ch.9 s.6.10.4	$\sum_{H,}{}^{cM,T} TD_{h,c} \times [(AQEW_{k,h}{}^{m,t} + SQEW_{k,h}{}^{i,t}) / \sum_{k,H}{}^{M,T} (AQEW_{k,h}{}^{m,t} + SQEW_{k,h}{}^{i,t})]$ Where 'C' is charge type 'c' 700. 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	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.
1800 MRP new	Day-Ahead Market Make-Whole Payment – Energy (DAM_MWP – DAM_COMP1) Component 1	MR Ch.9 ss.3.4.7, 3.4.14, and 3.4.15	Dispatchable Generation Resources that are not Pseudo-Units and Dispatchable Electricity Storage that are Registered to Inject $DAM\_COMP1_{k,h}^m = -1$ $\times [OP(DAM\_LMP_h^m, DAM\_QSI_{k,h}^m, DAM\_BE_{k,h}^m)$ $- OP(DAM\_LMP_h^m, DAM\_EOP_{k,h}^m, DAM\_BE_{k,h}^m)]$ Dispatchable Generation Resources that are Pseudo-Units: Combustion Turbine	Hourly	Due MP	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			$DAM\_COMP1_{k,h}^{c} = -1$ $\times \left[OP(DAM\_LMP_h^c, DAM\_QSI_{k,h}^c, DAM\_DIPC_{k,h}^c) - OP(DAM\_LMP_h^c, DAM\_EOP_{k,h}^c, DAM\_DIPC_{k,h}^c) \right]$ Dispatchable Generation Resources that are Pseudo-Units: Steam Turbine $DAM\_COMP1_{k,h}^{s} = -1$ $\times \left[OP(DAM\_LMP_h^s, DAM\_DIGQ_{k,h}^s, DAM\_DIPC_{k,h}^s) - OP(DAM\_LMP_h^s, DAM\_EOP\_DIGQ_{k,h}^s, DAM\_DIPC_{k,h}^s) \right]$						
1800 MRP new	Day-Ahead Market Make-Whole Payment – Energy (DAM_MWP – DAM_COMP1) Component 1	MR Ch.9 ss.3.4.13.1-3.4.13.4	Dispatchable Generation Resources – Hydroelectric Generation Resources Not Associated with Linked Forebays Hourly Basis Equation: $DAM\_COMP1_{k,h}^{m} = (-1)$ $\times \left[OP(DAM\_LMP_h^m, DAM\_QSI_{k,h}^m, DAM\_BE_{k,h}^m) - OP(DAM\_LMP_h^m, DAM\_EOP_{k,h}^m, DAM\_BE_{k,h}^m) - FROP_{k,h}^m \right]$ Per-Start Equation: $DAM\_COMP1_{k,s}^{m} = (-1)$ $\times \left\{ \left[\sum_{Hp} OP(DAM\_LMP_h^m, DAM\_QSI_{k,h}^m, DAM\_BE_{k,h}^m) - FROP_{k,h}^m \right] + \left[\sum_{Hn} OP(DAM\_LMP_h^m, DAM\_QSI_{k,h}^m, DAM\_BE_{k,h}^m) - OP(DAM\_LMP_h^m, DAM\_EOP_{k,h}^m, DAM\_BE_{k,h}^m) - FROP_{k,h}^m \right] \right\}$ Where: s = a start event consisting of a set of settlement hours for market participant 'k' at delivery point 'm', as determined in accordance with the applicable market manual; Hp = the set of all settlement hours within start 's' where $OP(DAM\_LMP_h^m, DAM\_QSI_{k,h}^m, DAM\_BE_{k,h}^m)$ is positive, excluding those settlement hours in which the resource has a reliability constraint;	Hourly	Due MP	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			H_n = the set of all settlement hours within a start 's' where $OP(DAM\_LMP_h^m, DAM\_QSI_{k,h}^m, DAM\_BE_{k,h}^m)$ is negative and $DAM\_QSI_{k,h}^m$ is greater than $DAM\_EOP_{k,h}^m$, excluding those settlement hours in which the resource has a reliability constraint or a binding constraint referred to in MR Ch.9 s.3.4.4.4; and where $FROP_{k,h}^m$ shall be determined as follows under both the Hourly Basis Equation and Per-Start Equation: if $DAM\_QSI_{k,h}^m$ is not equal to $FR\_UL_k^{m,f}$, or the resource does not have a forbidden region, then $FROP_{k,h}^m = 0$ otherwise: $FROP_{k,h}^m = OP(DAM\_LMP_h^m, FR\_UL_k^{m,f}, DAM\_BE_{k,h}^m)$ $\quad - OP(DAM\_LMP_h^m, Max(DAM\_EOP_{k,h}^m, FR\_LL_k^{m,f}), DAM\_BE_{k,h}^m)$ Where: $FR\_UL_k^{m,f}$ = the forbidden region upper limit from forbidden region set 'f' where $DAM\_QSI_{k,h}^m = FR\_UL_k^{m,f}$, as submitted by market participant 'k' for delivery point 'm' as daily dispatch data; $FR\_LL_k^{m,f}$ = the forbidden region lower limit from forbidden region set 'f' where $DAM\_QSI_{k,h}^m = FR\_UL_k^{m,f}$, as submitted by market participant 'k' for delivery point 'm' as daily dispatch data; and f = (1…N) of the forbidden region set $\{FR\_UL_k^{m,f}, FR\_LL_k^{m,f}\}$ and N is the maximum number of forbidden regions submitted by market participant 'k' for delivery point 'm' as daily dispatch data.							
1800 MRP new	Day-Ahead Market Make-Whole Payment – Energy (DAM_MWP – DAM_COMP1) Component 1	MR Ch.9 ss.3.4.13.2, 3.4.13.4 and 3.4.13.5	Dispatchable Generation Resources – Hydroelectric Generation Resources Associated with Linked Forebays The resource has: Attained Max Starts, then:	Hourly	Due MP	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			$$DAM\_COMP1_{k,s}^{m} = (-1)$$ $$\times \left\{ \left[\sum_{Hp} OP(DAM\_LMP_h^m, DAM\_QSI_{k,h}^m, DAM\_BE_{k,h}^m) - FROP_{k,h}^m \right] \right.$$ $$+ \left[\sum_{Hn} OP(DAM\_LMP_h^m, DAM\_QSI_{k,h}^m, DAM\_BE_{k,h}^m) \right.$$ $$\left. - OP(DAM\_LMP_h^m, DAM\_EOP_{k,h}^m, DAM\_BE_{k,h}^m) - FROP_{k,h}^m \right] \right\}$$ Where: s = a start event consisting of a set of settlement hours for market participant 'k' at delivery point 'm', as determined in accordance with the applicable market manual; Hp = the set of all settlement hours within start 's' where $OP(DAM\_LMP_h^m, DAM\_QSI_{k,h}^m, DAM\_BE_{k,h}^m)$ is positive, excluding those settlement hours in which the resource has a reliability constraint; Hn = the set of all settlement hours within a start 's' where $OP(DAM\_LMP_h^m, DAM\_QSI_{k,h}^m, DAM\_BE_{k,h}^m)$ is negative and $DAM\_QSI_{k,h}^m$ is greater than $DAM\_EOP_{k,h}^m$, excluding those settlement hours in which the resource has a reliability constraint or a binding constraint referred to in MR Ch.9 s.3.4.4.4; and where $FROP_{k,h}^m$ shall be determined as follows: if $DAM\_QSI_{k,h}^m$ is not equal to $FR\_UL_k^{m,f}$, or the resource does not have a forbidden region, then $FROP_{k,h}^m = 0$ otherwise: $$FROP_{k,h}^m = OP(DAM\_LMP_h^m, FR\_UL_k^{m,f}, DAM\_BE_{k,h}^m)$$ $$- OP(DAM\_LMP_h^m, Max(DAM\_EOP_{k,h}^m, FR\_LL_k^{m,f}), DAM\_BE_{k,h}^m)$$ Where: $FR\_UL_k^{m,f}$ = the forbidden region upper limit from forbidden region set 'f' where $DAM\_QSI_{k,h}^m = FR\_UL_k^{m,f}$, as submitted by market participant 'k' for delivery point 'm' as daily dispatch data; $FR\_LL_k^{m,f}$ = the forbidden region lower limit from forbidden region set 'f' where $DAM\_QSI_{k,h}^m = FR\_UL_k^{m,f}$, as submitted by market participant 'k' for delivery point 'm' as daily dispatch data; and f = (1…N) of the forbidden region set $\{FR\_UL_k^{m,f}, FR\_LL_k^{m,f}\}$ and N is the maximum number of forbidden regions submitted by market participant 'k' for delivery point 'm' as daily dispatch data.							

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			The resource has: Not Attained Max Starts; or Attained Max Starts but has a day-ahead schedule with settlement hours with a reliability constraint; or Attained Max Starts but has a day-ahead schedule with settlement hours that are not within a start event, as determined in accordance with the applicable market manual, then: $$DAM\_COMP1^m_{k,h+TL_m}$$ $$= (-1)$$ $$\times \{OP[DAM\_LMP^m_{h+TL_m}, DAM\_QSI^m_{k,h+TL_m}, DAM\_BE^m_{k,h+TL_m}]$$ $$- OP[DAM\_LMP^m_{h+TL_m}, DAM\_EOP^m_{k,h+TL_m}, DAM\_BE^m_{k,h+TL_m}] - FROP^m_{k,h+TL_m}\}$$ NOTE: hydroelectric generation resources associated with linked forebays, which are subject to this calculation of the DAM_MWP, shall only receive a DAM_MWP settlement amount for a settlement hour when the condition as set out in MR Ch.9 s.3.4.13.5.3 is true for such settlement hour. Where $FROP^m_{k,h+TL_m}$ shall be determined as follows: if $DAM\_QSI^m_{k,h+TL_m}$ is not equal to $FR\_UL^{m,f}_k$, or the resource does not have a forbidden region, then $FROP^m_{k,h+TL_m} = 0$ otherwise: $$FROP^m_{k,h+TL_m} = OP(DAM\_LMP^m_{h+TL_m}, FR\_UL^{m,f}_k, DAM\_BE^m_{k,h+TL_m})$$ $$- OP(DAM\_LMP^m_{h+TL_m}, Max(DAM\_EOP^m_{k,h+TL_m}, FR\_LL^{m,f}_k), DAM\_BE^m_{k,h+TL_m})$$ Where: TL_m = the time-lag, for each delivery point 'm', equal to the number of hours downstream that the delivery point is from the furthest upstream delivery point determined by the time-lag, submitted by the market participant in the daily dispatch data for the linked forebay; $FR\_UL^{m,f}_k$ = the forbidden region upper limit from forbidden region set 'f' where $DAM\_QSI^m_{k,h+TL_m} = FR\_UL^{m,f}_k$, as submitted by market participant 'k' for delivery point 'm' as daily dispatch data; $FR\_LL^{m,f}_k$ = the forbidden region lower limit from forbidden region set 'f' where $DAM\_QSI^m_{k,h+TL_m} = FR\_UL^{m,f}_k$, as submitted by market participant 'k' for delivery point 'm' as daily dispatch data; and							

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			f = (1…N) of the forbidden region set $\{FR\_UL_k^{m,f}, FR\_LL_k^{m,f}\}$ and N is the maximum number of forbidden regions submitted by market participant 'k' for delivery point 'm' as daily dispatch data.							
1800 MRP new	Day-Ahead Market Make-Whole Payment – Energy (DAM_MWP – DAM_COMP1) Component 1	MR Ch.9 s.3.4.8	Dispatchable Loads and Dispatchable Electricity Storage Resources that are Registered to Withdraw $$DAM\_COMP1_{k,h}^m = OP(DAM\_LMP_h^m, DAM\_QSW_{k,h}^m, DAM\_BL_{k,h}^m) \\ - OP(DAM\_LMP_h^m, DAM\_EOP_{k,h}^m, DAM\_BL_{k,h}^m)$$	Hourly	Due MP	13	N/A	N/A	N/A	
1800 MRP new	Day-Ahead Market Make-Whole Payment – Energy (DAM_MWP – DAM_COMP1) Component 1	MR Ch.9 s.3.4.9	Non-HDR Price Responsive Loads and Self-Scheduling Electricity Storage Resources that are Registered to Withdraw $$DAM\_COMP1_{k,h}^m = OP(DAM\_LMP_h^m, DAM\_QSW_{k,h}^m, DAM\_BL_{k,h}^m) \\ - OP(DAM\_LMP_h^m, DAM\_EOP_{k,h}^m, DAM\_BL_{k,h}^m)$$	Hourly	Due MP	13	N/A	N/A	N/A	
1800 MRP new	Day-Ahead Market Make-Whole Payment – Energy (DAM_MWP - DAM_COMP1) Component 1	MR Ch.9 s.3.4.10	Physical Hourly Demand Response Price Responsive Loads $$DAM\_COMP1_{k,h}^m = Max\{0, [OP(DAM\_LMP_h^m, DAM\_QSW_{k,h}^m, DAM\_BL_{k,h}^m) \\ - OP(DAM\_LMP_h^m, DAM\_EOP_{k,h}^m, DAM\_BL_{k,h}^m)]\} \\ + Max\{0, [OP(DAM\_LMP_h^m, DAM\_HDR\_QSW_{k,h}^m, DAM\_HDR\_BL_{k,h}^m) \\ - OP(DAM\_LMP_h^m, DAM\_EOP_{k,h}^m, DAM\_HDR\_BL_{k,h}^m)]\}$$ Where: m = the delivery point for the price responsive load and the physical hourly demand response resource associated with the price responsive load for metered market participant "k".	Hourly	Due MP	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
1800 MRP new	Day-Ahead Market Make-Whole Payment – Energy (DAM_MWP – DAM_COMP1) Component 1	MR Ch.9 s.3.4.11	Boundary Entity Resources – Imports $$DAM\_COMP1^i_{k,h} = -1 \times \left[OP(DAM\_LMP^i_h, DAM\_QSI^i_{k,h}, DAM\_BE^i_{k,h}) - OP(DAM\_LMP^i_h, DAM\_EOP^i_{k,h}, DAM\_BE^i_{k,h}) \right]$$	Hourly	Due MP	N/A	13	N/A	N/A	
1800 MRP new	Day-Ahead Market Make-Whole Payment – Energy (DAM_MWP – DAM_COMP1) Component 1	MR Ch.9 s.3.4.12	Boundary Entity Resources – Exports 1. $$DAM\_COMP1^i_{k,h} = OP(DAM\_LMP^i_h, DAM\_QSW^i_{k,h}, DAM\_BL^i_{k,h}) - OP(DAM\_LMP^i_h, DAM\_EOP^i_{k,h}, DAM\_BL^i_{k,h})$$	Hourly	Due MP	N/A	N/A	13	13	
1801 MRP new	Day-Ahead Market Make-Whole Payment – 10-Minute Spinning Reserve (DAM_MWP – DAM_COMP2) Component 2	MR Ch.9 ss.3.4.7, 3.4.14, and 3.4.15	Dispatchable Generation Resources that are not Pseudo-Units and Dispatchable Electricity Storage Resources that are Registered to Inject $$DAM\_COMP2^m_{k,h} = -1 \times \left[OP(DAM\_PROR^m_{r1,h}, DAM\_QSOR^m_{r1,k,h}, DAM\_BOR^m_{r1,k,h}) - OP(DAM\_PROR^m_{r1,h}, DAM\_OR\_EOP^m_{r1,k,h}, DAM\_BOR^m_{r1,k,h}) \right]$$ Dispatchable Generation Resources that are Pseudo-Units: Combustion Turbine $$DAM\_COMP2^c_{k,h} = -1 \times \left[OP(DAM\_PROR^c_{r1,h}, DAM\_QSOR^c_{r1,k,h}, DAM\_OR\_DIPC^c_{r1,k,h}) - OP(DAM\_PROR^c_{r1,h}, DAM\_OR\_EOP^c_{r1,k,h}, DAM\_OR\_DIPC^c_{r1,k,h}) \right]$$ Dispatchable Generation Resources that are Pseudo-Units: Steam Turbine	Hourly	Due MP	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			$DAM\_COMP2^s_{k,h} = -1$ $\times \left[OP\left(DAM\_PROR^s_{r1,h}, DAM\_QSOR^s_{r1,k,h}, DAM\_OR\_DIPC^s_{r1,k,h}\right) \right.$ $\left. - OP\left(DAM\_PROR^s_{r1,h}, DAM\_OR\_EOP^s_{r1,k,h}, DAM\_OR\_DIPC^s_{r1,k,h}\right)\right]$							
1801 MRP new (DAM_MWP – DAM_COMP2) Component 2	Day-Ahead Market Make-Whole Payment – 10-Minute Spinning Reserve	MR Ch.9 ss.3.4.13.3 and 3.4.13.4	Dispatchable Generation Resources – Hydroelectric Generation Resources Not Associated with Linked Forebays Hourly Basis Equation: $DAM\_COMP2^m_{k,h} = -1$ $\times \left[OP\left(DAM\_PROR^m_{r1,h}, DAM\_QSOR^m_{r1,k,h}, DAM\_BOR^m_{r1,k,h}\right) \right.$ $\left. - OP\left(DAM\_PROR^m_{r1,h}, DAM\_OR\_EOP^m_{r1,k,h}, DAM\_BOR^m_{r1,k,h}\right)\right]$ Per-Start Equation: $DAM\_COMP2^m_{k,s} = (-1)$ $\times \sum_H \left[OP\left(DAM\_PROR^m_{r1,h}, DAM\_QSOR^m_{r1,k,h}, DAM\_BOR^m_{r1,k,h}\right) \right.$ $\left. - OP\left(DAM\_PROR^m_{r1,h}, DAM\_OR\_EOP^m_{r1,k,h}, DAM\_BOR^m_{r1,k,h}\right)\right]$ Where: s = a start event consisting of a set of settlement hours for market participant 'k' at delivery point 'm', as determined in accordance with the applicable market manual; and H = the set of all settlement hours within start 's'.	Hourly	Due MP	13	N/A	N/A	N/A	
1801 MRP new (DAM_MWP – DAM_COMP2)	Day-Ahead Market Make-Whole Payment – 10-Minute Spinning Reserve	MR Ch.9 s.3.4.13.5	Dispatchable Generation Resources – Hydroelectric Generation Resources Associated with Linked Forebays The resource has: Attained Max Starts, then: $DAM\_COMP2^m_{k,s} = (-1)$ $\times \sum_H \left[OP\left(DAM\_PROR^m_{r1,h}, DAM\_QSOR^m_{r1,k,h}, DAM\_BOR^m_{r1,k,h}\right) \right.$ $\left. - OP\left(DAM\_PROR^m_{r1,h}, DAM\_OR\_EOP^m_{r1,k,h}, DAM\_BOR^m_{r1,k,h}\right)\right]$	Hourly	Due MP	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
	Component 2		Where: s = a start event consisting of a set of settlement hours for market participant 'k' at delivery point 'm', as determined in accordance with the applicable market manual; and H = the set of all settlement hours within start 's'. The resource has: Not Attained Max Starts; or Attained Max Starts but has a day-ahead schedule with settlement hours with a reliability constraint; or Attained Max Starts but has a day-ahead schedule with settlement hours that are not within a start event, as determined in accordance with the applicable market manual, then: $$DAM\_COMP2^m_{k,h+TL_m} = -1$$ $$\times \left[OP\left(DAM\_PROR^m_{r1,h+TL_m}, DAM\_QSOR^m_{r1,k,h+TL_m}, DAM\_BOR^m_{r1,k,h+TL_m}\right) \right.$$ $$\left. - OP\left(DAM\_PROR^m_{r1,h+TL_m}, DAM\_OR\_EOP^m_{r1,k,h+TL_m}, DAM\_BOR^m_{r1,k,h+TL_m}\right) \right]$$ NOTE: hydroelectric generation resources associated with linked forebays, which are subject to this calculation of the DAM_MWP, shall only receive a DAM_MWP settlement amount for a settlement hour when the condition as set out in MR Ch.9 s.3.4.13.5.3 is true for such settlement hour. Where: TL_m = the time-lag, for each delivery point 'm', equal to the number of hours downstream that the delivery point is from the furthest upstream delivery point determined by the time-lag, submitted by the market participant in the daily dispatch data for the linked forebay.						
1801 MRP new	Day-Ahead Market Make-Whole Payment – 10-Minute Spinning Reserve	MR Ch.9 s.3.4.8	Dispatchable Loads and Dispatchable Electricity Storage Resources that are Registered to Withdraw $$DAM\_COMP2^m_{k,h} = -1$$ $$\times \left[OP\left(DAM\_PROR^m_{r1,h}, DAM\_QSOR^m_{r1,k,h}, DAM\_BOR^m_{r1,k,h}\right) \right.$$ $$\left. - OP\left(DAM\_PROR^m_{r1,h}, DAM\_OR\_EOP^m_{r1,k,h}, DAM\_BOR^m_{r1,k,h}\right) \right]$$	Hourly	Due MP	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
	(DAM_MWP – DAM_COMP2) Component 2									
1802 MRP new	Day-Ahead Market Make-Whole Payment – 10-Minute Non-Spinning Reserve (DAM_MWP – DAM_COMP2) Component 2	MR Ch.9 ss.3.4.7, 3.4.14, and 3.4.15	Dispatchable Generation Resources that are not Pseudo-Units and Dispatchable Electricity Storage Resources that are Registered to Inject $DAM\_COMP2_{k,h}^m = -1$ $\times\ [OP(DAM\_PROR_{r2,h}^m, DAM\_QSOR_{r2,k,h}^m, DAM\_BOR_{r2,k,h}^m)$ $-\ OP(DAM\_PROR_{r2,h}^m, DAM\_OR\_EOP_{r2,k,h}^m, DAM\_BOR_{r2,k,h}^m)]$ Dispatchable Generation Resources that are Pseudo-Units: Combustion Turbine $DAM\_COMP2_{k,h}^c = -1$ $\times\ [OP(DAM\_PROR_{r2,h}^c, DAM\_QSOR_{r2,k,h}^c, DAM\_OR\_DIPC_{r2,k,h}^c)$ $-\ OP(DAM\_PROR_{r2,h}^c, DAM\_OR\_EOP_{r2,k,h}^c, DAM\_OR\_DIPC_{r2,k,h}^c)]$ Dispatchable Generation Resources that are Pseudo-Units: Steam Turbine $DAM\_COMP2_{k,h}^s = -1$ $\times\ [OP(DAM\_PROR_{r2,h}^s, DAM\_QSOR_{r2,k,h}^s, DAM\_OR\_DIPC_{r2,k,h}^s)$ $-\ OP(DAM\_PROR_{r2,h}^s, DAM\_OR\_EOP_{r2,k,h}^s, DAM\_OR\_DIPC_{r2,k,h}^s)]$	Hourly	Due MP	13	N/A	N/A	N/A	
1802 MRP new	Day-Ahead Market Make-Whole Payment – 10-Minute Non-Spinning Reserve (DAM_MWP – DAM_COMP2) Component 2	MR Ch.9 ss.3.4.13.3 and 3.4.13.4	Dispatchable Generation Resources – Hydroelectric Generation Resources Not Associated with Linked Forebays Hourly Basis Equation: $DAM\_COMP2_{k,h}^m = -1$ $\times\ [OP(DAM\_PROR_{r2,h}^m, DAM\_QSOR_{r2,k,h}^m, DAM\_BOR_{r2,k,h}^m)$ $-\ OP(DAM\_PROR_{r2,h}^m, DAM\_OR\_EOP_{r2,k,h}^m, DAM\_BOR_{r2,k,h}^m)]$ Per-Start Equation:	Hourly	Due MP	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			$DAM\_COMP2_{k,s}^{m} = (-1)$ $\times \sum_{H} [OP(DAM\_PROR_{r2,h}^{m}, DAM\_QSOR_{r2,k,h}^{m}, DAM\_BOR_{r2,k,h}^{m})$ $- OP(DAM\_PROR_{r2,h}^{m}, DAM\_OR\_EOP_{r2,k,h}^{m}, DAM\_BOR_{r2,k,h}^{m})]$ Where: s = a start event consisting of a set of settlement hours for market participant 'k' at delivery point 'm', as determined in accordance with the applicable market manual; and H = the set of all settlement hours within start 's'.							
1802 MRP new	Day-Ahead Market Make-Whole Payment – 10-Minute Non-Spinning Reserve (DAM_MWP – DAM_COMP2) Component 2	MR Ch.9 s.3.4.13.5	Dispatchable Generation Resources – Hydroelectric Generation Resources Associated with Linked Forebays The resource has Attained Max Starts, then: $DAM\_COMP2_{k,s}^{m} = (-1)$ $\times \sum_{H} [OP(DAM\_PROR_{r2,h}^{m}, DAM\_QSOR_{r2,k,h}^{m}, DAM\_BOR_{r2,k,h}^{m})$ $- OP(DAM\_PROR_{r2,h}^{m}, DAM\_OR\_EOP_{r2,k,h}^{m}, DAM\_BOR_{r2,k,h}^{m})]$ Where: s = a start event consisting of a set of settlement hours for market participant 'k' at delivery point 'm', as determined in accordance with the applicable market manual; and H = the set of all settlement hours within start 's'. The resource has: Not Attained Max Starts; or Attained Max Starts but has a day-ahead schedule with settlement hours with a reliability constraint; or Attained Max Starts but has a day-ahead schedule with settlement hours that are not within a start event, as determined in accordance with the applicable market manual, then:	Hourly	Due MP	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			$DAM\_COMP2^m_{k,h+TL_m} = -1$ $\times [OP(DAM\_PROR^m_{r2,h+TL_m}, DAM\_QSOR^m_{r2,k,h+TL_m}, DAM\_BOR^m_{r2,k,h+TL_m})$ $- OP(DAM\_PROR^m_{r2,h+TL_m}, DAM\_OR\_EOP^m_{r2,k,h+TL_m}, DAM\_BOR^m_{r2,k,h+TL_m})]$ NOTE: hydroelectric generation resources associated with linked forebays, which are subject to this calculation of the DAM_MWP, shall only receive a DAM_MWP settlement amount for a settlement hour when the condition as set out in MR Ch.9 s.3.4.13.5.3 is true for such settlement hour. Where: TL_m = the time-lag, for each delivery point 'm', equal to the number of hours downstream that the delivery point is from the furthest upstream delivery point determined by the time-lag, submitted by the market participant in the daily dispatch data for the linked forebay.						
1802 MRP new	Day-Ahead Market Make-Whole Payment – 10-Minute Non-Spinning Reserve (DAM_MWP – DAM_COMP2) Component 2	MR Ch.9 s.3.4.8	Dispatchable Loads and Dispatchable Electricity Storage Resources that are Registered to Withdraw $DAM\_COMP2^m_{k,h} = -1$ $\times [OP(DAM\_PROR^m_{r2,h}, DAM\_QSOR^m_{r2,k,h}, DAM\_BOR^m_{r2,k,h})$ $- OP(DAM\_PROR^m_{r2,h}, DAM\_OR\_EOP^m_{r2,k,h}, DAM\_BOR^m_{r2,k,h})]$	Hourly	Due MP	13	N/A	N/A	N/A	
1802 MRP new	Day-Ahead Market Make-Whole Payment – 10-Minute Non-Spinning Reserve (DAM_MWP – DAM_COMP2)	MR Ch.9 s.3.4.11	Boundary Entity Resources - Imports $DAM\_COMP2^i_{k,h} = -1 \, x \, [OP(DAM\_PROR^i_{r2,h}, DAM\_QSOR^i_{r2,k,h}, DAM\_BOR^i_{r2,k,h})$ $- OP(DAM\_PROR^i_{r2,h}, DAM\_OR\_EOP^i_{r2,k,h}, DAM\_BOR^i_{r2,k,h})]$	Hourly	Due MP	N/A	13	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
	Component 2									
1802 MRP new	Day-Ahead Market Make-Whole Payment – 10-Minute Non-Spinning Reserve (DAM_MWP – DAM_COMP2) Component 2	MR Ch.9 s.3.4.12	Boundary Entity Resources – Exports $$DAM\_COMP2_{k,h}^{i} = -1 \, x \, \big[OP\big(DAM\_PROR_{r2,h}^{i}, DAM\_QSOR_{r2,k,h}^{i}, DAM\_BOR_{r2,k,h}^{i}\big) - OP\big(DAM\_PROR_{r2,h}^{i}, DAM\_OR\_EOP_{r2,k,h}^{i}, DAM\_BOR_{r2,k,h}^{i}\big) \big]$$	Hourly	Due MP	N/A	N/A	13	13	
1803 MRP new	Day-Ahead Market Make-Whole Payment – 30-Minute Operating Reserve (DAM_MWP – DAM_COMP2) Component 2	MR Ch.9 ss.3.4.7, 3.4.14, and 3.4.15	Dispatchable Generation Resources that are not Pseudo-Units and Dispatchable Electricity Storage Resources that are Registered to Inject $$DAM\_COMP2_{k,h}^{m} = -1 \\ \times \big[OP\big(DAM\_PROR_{r3,h}^{m}, DAM\_QSOR_{r3,k,h}^{m}, DAM\_BOR_{r3,k,h}^{m}\big) - OP\big(DAM\_PROR_{r3,h}^{m}, DAM\_OR\_EOP_{r3,k,h}^{m}, DAM\_BOR_{r3,k,h}^{m}\big) \big]$$ Dispatchable Generation Resources that are Pseudo-Units: Combustion Turbine $$DAM\_COMP2_{k,h}^{c} = -1 \\ \times \big[OP\big(DAM\_PROR_{r3,h}^{c}, DAM\_QSOR_{r3,k,h}^{c}, DAM\_OR\_DIPC_{r3,k,h}^{c}\big) - OP\big(DAM\_PROR_{r3,h}^{c}, DAM\_OR\_EOP_{r3,k,h}^{c}, DAM\_OR\_DIPC_{r3,k,h}^{c}\big) \big]$$ Dispatchable Generation Resources that are Pseudo-Units: Steam Turbine $$DAM\_COMP2_{k,h}^{s} = -1 \\ \times \big[OP\big(DAM\_PROR_{r3,h}^{s}, DAM\_QSOR_{r3,k,h}^{s}, DAM\_OR\_DIPC_{r3,k,h}^{s}\big) - OP\big(DAM\_PROR_{r3,h}^{s}, DAM\_OR\_EOP_{r3,k,h}^{s}, DAM\_OR\_DIPC_{r3,k,h}^{s}\big) \big]$$	Hourly	Due MP	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
1803 MRP new	Day-Ahead Market Make-Whole Payment – 30-Minute Operating Reserve (DAM_MWP – DAM_COMP2) Component 2	MR Ch.9 ss.3.4.13.3 and 3.4.13.4	Dispatchable Generation Resources – Hydroelectric Generation Resources Not Associated with Linked Forebays Hourly Basis Equation: $DAM\_COMP2^m_{k,h} = -1$ $\times [OP(DAM\_PROR^m_{r3,h}, DAM\_QSOR^m_{r3,k,h}, DAM\_BOR^m_{r3,k,h})$ $- OP(DAM\_PROR^m_{r3,h}, DAM\_OR\_EOP^m_{r3,k,h}, DAM\_BOR^m_{r3,k,h})]$ Per-Start Equation: $DAM\_COMP2^m_{k,s} = (-1)$ $\times \sum_H [OP(DAM\_PROR^m_{r3,h}, DAM\_QSOR^m_{r3,k,h}, DAM\_BOR^m_{r3,k,h})$ $- OP(DAM\_PROR^m_{r3,h}, DAM\_OR\_EOP^m_{r3,k,h}, DAM\_BOR^m_{r3,k,h})]$ Where: s = a start event consisting of a set of settlement hours for market participant 'k' at delivery point 'm', as determined in accordance with the applicable market manual; and H = the set of all settlement hours within start 's'.	Hourly	Due MP	13	N/A	N/A	N/A	
1803 MRP new	Day-Ahead Market Make-Whole Payment – 30-Minute Operating Reserve (DAM_MWP – DAM_COMP2) Component 2	MR Ch.9 s.3.4.13.5	Dispatchable Generation Resources – Hydroelectric Generation Resources Associated with Linked Forebays The resource has Attained Max Starts, then: $DAM\_COMP2^m_{k,s} = (-1)$ $\times \sum_H [OP(DAM\_PROR^m_{r3,h}, DAM\_QSOR^m_{r3,k,h}, DAM\_BOR^m_{r3,k,h})$ $- OP(DAM\_PROR^m_{r3,h}, DAM\_OR\_EOP^m_{r3,k,h}, DAM\_BOR^m_{r3,k,h})]$ Where: s = a start event consisting of a set of settlement hours for market participant 'k' at delivery point 'm', as determined in accordance with the applicable market manual; and	Hourly	Due MP	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			H = the set of all settlement hours within start 's'. The resource has: Not Attained Max Starts; or Attained Max Starts but has a day-ahead schedule with settlement hours with a reliability constraint; or Attained Max Starts but has a day-ahead schedule with settlement hours that are not within a start event, as determined in accordance with the applicable market manual, then: $$DAM\_COMP2^m_{k,h+TL_m} = -1 \\ \times [OP(DAM\_PROR^m_{r3,h+TL_m}, DAM\_QSOR^m_{r3,k,h+TL_m}, DAM\_BOR^m_{r3,k,h+TL_m}) \\ - OP(DAM\_PROR^m_{r3,h+TL_m}, DAM\_OR\_EOP^m_{r3,k,h+TL_m}, DAM\_BOR^m_{r3,k,h+TL_m})]$$ NOTE: hydroelectric generation resources associated with linked forebays, which are subject to this calculation of the DAM_MWP, shall only receive a DAM_MWP settlement amount for a settlement hour when the condition as set out in MR Ch.9 s.3.4.13.5.3 is true for such settlement hour. Where: TL_m = the time-lag, for each delivery point 'm', equal to the number of hours downstream that the delivery point is from the furthest upstream delivery point determined by the time-lag, submitted by the market participant in the daily dispatch data for the linked forebay.						
1803 MRP new	Day-Ahead Market Make-Whole Payment – 30-Minute Operating Reserve (DAM_MWP – DAM_COMP2) Component 2	MR Ch.9 s.3.4.8	Dispatchable Loads and Dispatchable Electricity Storage Resources that are Registered to Withdraw $$DAM\_COMP2^m_{k,h} = -1 \\ \times [OP(DAM\_PROR^m_{r3,h}, DAM\_QSOR^m_{r3,k,h}, DAM\_BOR^m_{r3,k,h}) \\ - OP(DAM\_PROR^m_{r3,h}, DAM\_OR\_EOP^m_{r3,k,h}, DAM\_BOR^m_{r3,k,h})]$$	Hourly	Due MP	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
1803 MRP new	Day-Ahead Market Make-Whole Payment – 30-Minute Operating Reserve (DAM_MWP – DAM_COMP2) Component 2	MR Ch.9 s.3.4.11	Boundary Entity Resources – Imports $$DAM\_COMP2^i_{k,h} = -1\,x\,[OP(DAM\_PROR^i_{r3,h}, DAM\_QSOR^i_{r3,k,h}, DAM\_BOR^i_{r3,k,h}) - OP(DAM\_PROR^i_{r3,h}, DAM\_OR\_EOP^i_{r3,k,h}, DAM\_BOR^i_{r3,k,h})]$$	Hourly	Due MP	N/A	13	N/A	N/A	
1803 MRP new	Day-Ahead Market Make-Whole Payment – 30-Minute Operating Reserve (DAM_MWP – DAM_COMP2) Component 2	MR Ch.9 s.3.4.12	Boundary Entity Resources - Exports $$DAM\_COMP2^i_{k,h} = -1\,x\,[OP(DAM\_PROR^i_{r3,h}, DAM\_QSOR^i_{r3,k,h}, DAM\_BOR^i_{r3,k,h}) - OP(DAM\_PROR^i_{r3,h}, DAM\_OR\_EOP^i_{r3,k,h}, DAM\_BOR^i_{r3,k,h})]$$	Hourly	Due MP	N/A	N/A	13	13	
1804 MRP new	Day-Ahead Market Generator Offer Guarantee – Energy (DAM_GOG – DAM_GOG_COMP1)	MR Ch.9 ss.4.4.6, 4.4.15, and 4.4.22	GOG-eligible Resources that are not Pseudo-Units $$DAM\_GOG\_COMP1^m_k = \sum^{H}[-1\,x\,(OP(DAM\_LMP^m_h, DAM\_QSI^m_{k,h}, DAM\_BE^m_{k,h})) + (DAM\_BE\_SNL^m_{k,h}\,x\,N^m_{k,h}/12)] - \sum^{RH}[DAM\_LMP^m_h\,x\,DAM\_QSI^m_{k,h}]$$ Where: H = the set of settlement hours within the relevant day-ahead commitment period; RH = the set of contiguous settlement hours with day-ahead schedules for the ramp-up period;	Hourly	Either Way	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
	Component 1		$N_{k,h}^m$= the number of metering intervals in settlement hour 'h' during which delivery point 'm' for market participant 'k' was synchronized and injecting energy into the IESO-controlled grid; and if the combustion turbine resource or steam turbine resource is registered as a pseudo-unit but is not operating as a pseudo-unit and has a minimum constraint applied for combined cycle operation consistent with combustion turbine commitment, then $DAM\_QSI_{k,h}^m$ will be replaced with $DAM\_EOP_{k,h}^m$ for those settlement hours in which they have such constraint. GOG-eligible Resources that are Pseudo-Units: Combustion Turbine $$DAM\_GOG\_COMP1_k^c = \sum^H \left[(-1) \; x \; OP(DAM\_LMP_h^c, DAM\_QSI_{k,h}^c, DAM\_DIPC_{k,h}^c) + DAM\_BE\_SNL_{k,h}^p \times \frac{N_{k,h}^c}{12} \right.$$ $$\left. \times \left(1 - ST\_Portion_{k,d1}^p \right) \right] - \sum^{RH} \left[DAM\_LMP_h^c \; x \; DAM\_QSI_{k,h}^c \right]$$ Where: H = the set of settlement hours within the combustion turbine resource's relevant day-ahead commitment period; RH = the set of contiguous settlement hours that the combustion turbine resource has a day-ahead schedule for the ramp-up period, scheduled greater than zero but less than the combustion turbine resource's minimum loading point; p = the pseduo-unit associated with combustion turbine resource delivery point 'c'; and $N_{,h}^c$= the number of metering intervals in settlement hour 'h' during which combustion turbine resource delivery point 'c' for market participant 'k' was synchronized and injecting energy into the IESO-controlled grid. GOG-eligible Resources that are Pseudo-Units: Steam Turbine $$DAM\_GOG\_COMP1_k^s = \sum^H \left[(-1) \times OP\left(DAM\_LMP_h^s, DAM\_DIGQ_{k,h}^s, DAM\_DIPC_{k,h}^s \right) \right.$$ $$\left. + \sum_{p=1}^M \left(DAM\_BE\_SNL_{k,h}^p \times \frac{N_{k,h}^p}{12} \times ST\_Portion_{k,d1}^p \right) \right] - \sum^{RH} \left[DAM\_LMP_h^s \; x \; DAM\_QSI_{k,h}^s \right]$$ Where:							

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			H = the set of all settlement hours within the steam turbine resource's day-ahead commitment period when at least one of the pseudo-units associated with the steam turbine resource has a day-ahead schedule greater than or equal to its respective pseudo-unit's minimum loading point; M = the set of all pseudo-units 'p' associated with steam turbine resource delivery point 's' that have a day-ahead schedule greater than or equal to their respective minimum loading point in settlement hour 'h'; RH = the set of all settlement hours in the steam turbine resource's day-ahead operational commitment when all of the pseudo-units associated with the steam turbine resource are scheduled less than their minimum loading point; and $N_{k,h}^{p}$ = the number of metering intervals in the settlement hour 'h' during which the combustion turbine resource associated with pseudo-unit 'p' for market participant 'k' was synchronized and injecting energy into the IESO-controlled grid.							
1805 MRP new	Day-Ahead Market Generator Offer Guarantee – Operating Reserve (DAM_GOG – DAM_GOG_COMP2) Component 2	MR Ch.9 ss.4.4.7, 4.4.16, and 4.4.23	GOG-eligible Resources that are not Pseudo-Units $$DAM\_GOG\_COMP2_k^m = -1\ x \sum_{R}^{H}\left[OP\left(DAM\_PROR_{r,h}^m, DAM\_QSOR_{r,k,h}^m, DAM\_BOR_{r,k,h}^m\right)\right]$$ Where: H = the set of settlement hours within the relevant day-ahead commitment period. GOG-eligible Resources that are Pseudo-Units: Combustion Turbine $$DAM\_GOG\_COMP2_k^c = \sum_{R}^{R}\sum_{}^{H}\left[(-1) \times OP\left(DAM\_PROR_{r,h}^c, DAM\_QSOR_{r,k,h}^c, DAM\_OR\_DIPC_{r,k,h}^c\right)\right]$$ Where: H = the set of settlement hours within the combustion turbine resource's relevant day-ahead commitment period. GOG-eligible Resources that are Pseudo-Units: Steam Turbine $$DAM\_GOG\_COMP2_k^s = \sum_{}^{R}\sum_{}^{H}\left[(-1) \times OP\left(DAM\_PROR_{r,h}^s, DAM\_QSOR_{r,k,h}^s, DAM\_OR\_DIPC_{r,k,h}^s\right)\right]$$ Where:	Hourly	Either Way	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			H = the set of all settlement hours within the steam turbine resource's day-ahead commitment period when at least one of the pseudo-units associated with the steam turbine resource has a day-ahead schedule greater than or equal to its respective pseudo-unit's minimum loading point.							
1806 MRP new	Day-Ahead Market Generator Offer Guarantee – Over Midnight (DAM_GOG – DAM_GOG_COMP3) Component 3	MR Ch.9 ss.4.4.8, 4.4.17, and 4.4.24	NOTE: this charge type has -1 added before the summation sign as it has been separated from the larger DAM_GOG equation within the market rules, in which this component would have been subtracted from the total settlement amount. GOG-eligible Resources that are not Pseudo-Units $$DAM\_GOG\_COMP3_k^m = -1 \times \sum^H [(-1) \ x \ (OP(DAM\_LMP_h^m, MLP_k^m, DAM\_BE_{k,h}^m)) + DAM\_BE\_SNL_{k,h}^m]$$ Where: H = the set of settlement hours within the day-ahead commitment period that are required to complete the resource's minimum generation block run-time that began in Day 0; MLP_k^m = the minimum loading point of the GOG-eligible resource for Day 0 for market participant 'k' for delivery point 'm'; and $N_{k,h}^m$ = the number of metering intervals in settlement hour 'h' during which delivery point 'm' for market participant 'k' was synchronized and injecting energy into the IESO-controlled grid. GOG-eligible Resources that are Pseudo-Units: Combustion Turbine $$DAM\_GOG\_COMP3_k^c = -1$$ $$\times \sum^H \left[(-1)x \ OP(DAM\_LMP_h^c, MLP_k^c, DAM\_DIPC_{k,h}^c) + DAM\_BE\_SNL_{k,h}^p \times \frac{N_{k,h}^c}{12} \right.$$ $$\left. \times (1 - ST\_Portion_{k,d1}^p) \right]$$ Where: H = the set of settlement hours within the day-ahead commitment period that are required to complete the associated pseudo-unit's minimum generation block run-time that began in Day 0; p = the pseudo-unit associated with combustion turbine resource delivery point 'c'; MLP_k^c = the minimum loading point of the combustion turbine resource associated with combustion turbine resource delivery point 'c'; and	Hourly	Either Way	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			$N_{k,h}^c$ = the number of metering intervals in settlement hour 'h' during which combustion turbine resource delivery point 'c' for market participant 'k' was synchronized and injecting energy into the IESO-controlled grid. GOG-eligible Resources that are Pseudo-Units: Steam Turbine $$DAM\_GOG\_COMP3_k^s = -1$$ $$\times \sum\nolimits^V \sum\nolimits^{MHR_p} \left[(-1) \times OP\left(DAM\_LMP_h^s, MLP_k^s, DAM\_DIPC_{k,h}^s\right) + DAM\_BE\_SNL_{k,h}^p \times \frac{N_{k,h}^p}{12} \right.$$ $$\left. \times ST\_Portion_{k,d1}^p \right]$$ Where: V = the set of all pseudo-units 'p' associated with steam turbine resource delivery point 's' whose associated combustion turbine resource has a variant #2 (per MR Ch.9. s.4.4.13) day-ahead operational commitment that overlaps with the steam turbine resource day-ahead operational commitment; MHRp = the set of all settlement hours within the day-ahead commitment period that are required to complete minimum generation block run-time that began in Day 0 for pseudo-unit 'p' associated with the steam turbine resource; MLP_k^p = the minimum loading point of steam turbine resource associated with pseudo-unit 'p' for market participant 'k'; and $N_{k,h}^p$ = the number of metering intervals in the settlement hour 'h' during which the combustion turbine resource associated with pseudo-unit 'p' for market participant 'k' was synchronized and injecting energy into the IESO-controlled grid.							
1807 MRP new	Day-Ahead Market Generator Offer Guarantee – Start-up (DAM_GOG – DAM_GOG_COMP4)	MR Ch.9 ss.4.4.9, 4.4.18, and 4.4.25	GOG-eligible Resources that are not Pseudo-Units achieves minimum loading point within the first six metering intervals of the first settlement hour of its day-ahead operational commitment: $$DAM\_GOG\_COMP4_{k,h}^m = DAM\_BE\_SU_{k,h}^m$$ achieves minimum loading point after the first six metering intervals of the start of its minimum generation block run-time but before the 19th metering interval following the start of its minimum generation block run-time:	Hourly	Due MP	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
	Component 4		$DAM\_GOG\_COMP4_{k,h}^{m} = DAM\_BE\_SU_{k,h}^{m} - (DAM\_BE\_SU_{k,h}^{m} \times N\_INT /12)$ Where: N_INT = the number of metering intervals after the first six metering intervals that the GOG-eligible resource took to achieve its minimum loading point. otherwise: $DAM\_GOG\_COMP4_{k,h}^{m} = 0$ GOG-eligible Resources that are Pseudo-Units: Combustion Turbine achieves minimum loading point within the first six metering intervals of the first settlement hour of its day-ahead operational commitment: $DAM\_GOG\_COMP4_{k,h}^{c} = DAM\_BE\_SU_{k,h}^{p} \times (1 - ST\_Portion_{k,d1}^{p})$ achieves minimum loading point after the first six metering intervals of the start of its day-ahead operational commitment but before the 19th metering interval following the start of its day-ahead operational commitment: $DAM\_GOG\_COMP4_{k,h}^{c} = DAM\_BE\_SU_{k,h}^{p} \times \left(1 - \dfrac{N\_INT}{12}\right) \times (1 - ST\_Portion_{k,d1}^{p})$ Where: N_INT = the number of metering intervals after the first six metering intervals that the combustion turbine resource took to achieve its minimum loading point otherwise: $DAM\_GOG\_COMP4_{k,h}^{c} = 0$ GOG-eligible Resources that are Pseudo-Units: Steam Turbine $DAM\_GOG\_COMP4_{k,h}^{s} = \sum_{c=1}^{C} \sum_{x=1}^{X_c} \left[DAM\_GOG\_COMP4_{k,x}^{c} \times \dfrac{ST\_Portion_{k,d1}^{p}}{(1 - ST\_Portion_{k,d1}^{p})} \right]$ Where:							

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			C = the set of all combustion turbine resource delivery points 'c' associated with steam turbine resource delivery point 's'; $DAM\_GOG\_COMP4^c_{k,x}$ = determined in accordance with MR Ch.9 s.4.4.18 for combustion turbine resource delivery point "c" for market participant 'k' for day-ahead commitment period 'x'; and Xc = the set of all day-ahead operational commitment periods 'x' for combustion turbine resource delivery point 'c' that are entitled to a day-ahead market generator offer guarantee settlement amount pursuant to MR Ch.9 s.4.4.12 (variant #1) that overlap with the steam turbine resource's day-ahead commitment period.							
1808 MRP new	Day-Ahead Market Generator Offer Guarantee – DAM Make-Whole Payment Offset (DAM_GOG – DAM_GOG_COMP5) Component 5	MR Ch.9 ss.4.4.11, 4.4.20, and 4.4.26	NOTE: this charge type has -1 added before the summation sign as it has been separated from the larger DAM_GOG equation within the market rules, in which this component would have been subtracted from the total settlement amount. GOG-eligible Resources that are not Pseudo-Units $DAM\_GOG\_COMP5^m_{k,h} = -1 \times \sum^{H} DAM\_MWP^m_{k,h}$ Where: H = the set of settlement hours within the relevant day-ahead commitment period. GOG-eligible Resources that are Pseudo-Units: Combustion Turbine $DAM\_GOG\_COMP5^c_{k,h} = -1 \times \sum^{H} DAM\_MWP^c_{k,h}$ Where: H = the set of settlement hours within the combustion turbine resource's relevant day-ahead commitment period. GOG-eligible Resources that are Pseudo-Units: Steam Turbine $DAM\_GOG\_COMP5^s_{k,h} = -1 \times \sum^{H} DAM\_MWP^s_{k,h}$ Where:	Hourly	Due IESO	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			H = the set of all settlement hours within the steam turbine resource's day-ahead commitment period when at least one of the pseudo-units associated with steam turbine resource delivery point 's' has a day-ahead schedule greater than or equal to its respective minimum loading point.							
1815 MRP new	Day-Ahead Market Balancing Credit - Energy (DAM_BCE)	MR Ch.9 s.3.3	GOG-eligible Resources $$DAM\_BCE_{k,h}^m = \sum^T Max\left[0, \left(RT\_LMP_h^{m,t} - DAM\_LMP_h^m\right) \times Max\left(0, \left(DAM\_QSI_{k,h}^m - AQEI_{k,h}^{m,t}\right)\right)\right]/12$$ Boundary Entity Resources for an import transaction: $$DAM\_BCE_{k,h}^i = Max\{0, \sum^T OP(RT\_LMP_h^{i,t}, Min(RT\_LOC\_EOP_{k,h}^{i,t}, DAM\_QSI_{k,h}^i), BE_{k,h}^{i,t}) \\ - OP(RT\_LMP_h^{i,t}, SQEI_{k,h}^{i,t}, BE_{k,h}^{i,t})\}/12$$ for an export transaction: $$DAM\_BCE_{k,h}^i = -1 \times Min\{0, \sum^T OP(RT\_LMP_h^{i,t}, Min(RT\_LOC\_EOP_{k,h}^{i,t}, DAM\_QSW_{k,h}^i), BL_{k,h}^{i,t}) \\ - OP(RT\_LMP_h^{i,t}, SQEW_{k,h}^{i,t}, BL_{k,h}^{i,t})\}/12$$	Interval	Due MP	13	13	13	13	
1816 MRP new	Day-Ahead Market Balancing Credit – Operating Reserve (DAM_BCOR)	MR Ch.9 s.3.3	GOG-eligible Resources $$DAM\_BCOR_{k,h}^m = \sum^{R,T} Max\left(0, RT\_PROR_{r,h}^{m,t} - DAM\_PROR_{r,h}^m\right) \\ \times Max\left(0, DAM\_QSOR_{r,k,h}^m - RT\_QSOR_{r,k,h}^{m,t}\right)/12$$ Boundary Entity Resources	Interval	Due MP	13	13	13	13	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			$$DAM\_BCOR_{k,h}^{i} = \sum^{R} Max\{0, \sum^{T} OP(RT\_PROR_{r,h}^{i,t}, Min(RT\_OR\_LOC\_EOP_{r,k,h}^{i,t}, DAM\_QSOR_{r,k,h}^{i}), BOR_{r,k,h}^{i,t}) - OP(RT\_PROR_{r,h}^{i,t}, RT\_QSOR_{r,k,h}^{i,t}, BOR_{r,k,h}^{i,t})\}/12$$							
1828 MRP new	Day-Ahead Market Import Failure Charge (DAM_IMFC)	MR Ch.9 ss.3.7A.1 and 3.7A.2	$$DAM\_IMFC_{k,h}^{i} = \sum^{T} Min\left(0, RT\_PEC_{h}^{i,t} + RT\_PNISL_{h}^{i,t}\right) \times DAM\_ISD_{k,h}^{i,t}/12)$$ Where: a. $DAM\_ISD_{k,h}^{i,t} = Max\left(Min\left(DAM\_QSI_{k,h}^{i}, PD\_QSI_{k,h}^{i}\right) - SQEI_{k,h}^{i,t}, 0\right)$	Interval	Due IESO	N/A	13	N/A	N/A	
1829 MRP new	Day-Ahead Market Export Failure Charge (DAM_EXFC)	MR Ch.9 ss.3.7A.1 and 3.7A.3	$$DAM\_EXFC_{k,h}^{i} = \sum^{T}(-1) \times Max\left(0, RT\_PEC_{h}^{i,t} + RT\_PNISL_{h}^{i,t}\right) \times DAM\_ESD_{k,h}^{i,t}/12)$$ Where: a. $DAM\_ESD_{k,h}^{i,t} = DAM\_ESD_{k,h}^{i,t} = Max\left(Min\left(DAM\_QSW_{k,h}^{i}, PD\_QSW_{k,h}^{i}\right) - SQEW_{k,h}^{i,t}, 0\right)$	Interval	Due IESO	N/A	N/A	0	13	
1830	Tariff Response charge for Exports	MR Ch.10 s.4.6	$-1 \times \sum_{T} SQEW_{k,h}^{i,t}/12 \times PRICE$	Hourly	Due IESO	N/A	N/A	0	N/A	Ontario regulation 25/25
1850 MRP new	Day-Ahead Market Uplift (DAM_UPL)	MR Ch.9 s.4.14.3	$$DAM\_UPL_{k} = -1 \times \left(\sum_{H}^{M}\left(DAM\_MWP_{k,h}^{m} + DAM\_GOG_{k}^{m}\right) - DAM\_P2\_PMT\right) \times \sum_{H}^{M,T}\left(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}\right)/\sum_{K,H}^{M,T}\left(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}\right)$$ Where:	Daily	Due IESO	13	N/A	0	13	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			$DAM\_MWP_{k,h}^m$ = is the day-ahead market make-whole payment settlement amount for charge types 1800, 1801, 1802 and 1803, calculated in accordance with MR Ch.9 s.3.4 for market participant 'k' at delivery point 'm' for settlement hour 'h'; $DAM\_GOG_k^m$ = is the day-ahead market generator offer guarantee settlement amount for charge types 1804, 1805, 1806, 1807 and 1808, calculated in accordance with MR Ch.9 s.4.4 for market participant 'k' at delivery point 'm'; and DAM_P2_PMT = calculated in accordance with MR Ch.9 s.4.14.5.							
1851 MRP new Day-Ahead Market Reliability Scheduling Uplift (DRSU – EL_DRSU)	Day-Ahead Market Reliability Scheduling Uplift (DRSU – EL_DRSU)	MR Ch.9 s.4.14.4	Load Resources, Electricity Storage Resources that are Registered to Withdraw, and Boundary Entity Resources – Export Transactions $EL\_DRSU_k = \left(DAM\_P2\_PMT - \sum_K V\_DRSU_k\right) \times \sum_H^{M,T}(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t})/\sum_{K,H}^{M,T}(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t})$ Where: V_DRSU_k = the DRSU settlement amount calculated for charge type 1852 in accordance with MR Ch.9 s.4.14.4.1 for market participant 'k' at delivery point 'v' for virtual zonal resources; and $DAM\_P2\_PMT = -1 \times \sum_{H,K}^M Max(Imp\_DAM\_MWP_{k,h}^{i,2} - Imp\_DAM\_MWP_{k,h}^{i,p1},0) + DAM\_GOG_{k,h}^m$ and where : $Imp\_DAM\_MWP_{k,h}^{i,p2} = Max[0, DAM\_COMP1_{k,h}^i + DAM\_COMP2_{k,h}^i]$ and each component is determined as follows: i. $DAM\_COMP1_{k,h}^i = -1 \times [OP(DAM\_LMP_h^i, DAM\_QSI_{k,h}^{i,p2}, DAM\_BE_{k,h}^i) - OP(DAM\_LMP_h^i, DAM\_EOP_{k,h}^i, DAM\_BE_{k,h}^i)]$ ii. $DAM\_COMP2_{k,h}^i = -1 \times \sum_R[OP(DAM\_PROR_{r,h}^i, DAM\_QSOR_{r,k,h}^{i,p2}, DAM\_BOR_{r,k,h}^i) - OP(DAM\_PROR_{r,h}^i, DAM\_OR\_EOP_{r,k,h}^i, DAM\_BOR_{r,k,h}^i)]$ $Imp\_DAM\_MWP_{k,h}^{i,p1} = Max[0, DAM\_COMP1_{k,h}^i + DAM\_COMP2_{k,h}^i]$ and each component is determined as follows:	Daily	Due IESO	13	N/A	0	13	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			a. $DAM\_COMP1_{k,h}^i = -1 \times [OP(DAM\_LMP_h^i, DAM\_QSI_{k,h}^{i,p1}, DAM\_BE_{kh}^i) - OP(DAM\_LMP_h^i, DAM\_EOP_{k,h}^i, DAM\_BE_{kh}^i)]$ b. $DAM\_COMP2_{k,h}^i = -1 \times \sum_R [OP(DAM\_PROR_{r,h}^i, DAM\_QSOR_{r,k,h}^{i,p1}, DAM\_BOR_{r,k,h}^i) - OP(DAM\_PROR_{r,h}^i, DAM\_OR\_EOP_{r,k,h}^i, DAM\_BOR_{r,k,h}^i)]$ $DAM\_GOG_{k,h}^m$ = calculated in accordance with MR Ch.9 s.4.4.						
1852 MRP new	Day-Ahead Market Reliability Scheduling Uplift – Virtual Transactions to Sell (DRSU - V_DRSU)	MR Ch.9 ss.4.14.4-4.14.4.1	Virtual Zonal Resources with Day-Ahead Schedules to Inject Energy $V\_DRSU_k = DAM\_P2\_PMT \times \sum_H^V DAM\_QVSI_{k,h}^v / \left(\sum_{K,H}^V DAM\_QVSI_{k,h}^v + DAM\_NDL\_OF \right)$ Where: $DAM\_NDL\_OF = Max[\sum_{H,K}^M (DAM\_QSW_{k,h}^{m,p2} + DAM\_HDR\_QSW_{k,h}^{m1,p2} - AQEW_h^{m,t}, 0)]$ and where: M = the set of all delivery points 'm' for non-dispatchable loads and physical hourly demand response resources that are not associated with load equipment registered as price responsive loads; m1 = the set of all delivery points 'm' for physical hourly demand response resources; and p2 = Pass 2: Reliability Scheduling and Commitment of the day-ahead market calculation engine.	Daily	Due IESO	N/A	N/A	N/A	N/A	
1865 MRP new	Day-Ahead Market Balancing Credit Uplift (DAM_BCU)	MR Ch.9 s.3.11	$= \sum_C^{M,T} TD_{k,h,c} \ x \left[\sum^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t} + RQ_{k,h}^{m,i,t}) / \sum_K^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}) \right]$ Where: C = the set of all charge types 'c' as follows: 1815,1816.	Hourly	Due IESO	13	N/A	0	13	
1880	Tariff Response Charge for Exports	MR Ch.10 s.4.6	$-1 \ x \sum_K TD_k \ 1830$	Hourly	Due IESO	N/A	N/A	0	N/A	Ontario Regulation 25/25

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
	Balancing Amount									
1900 MRP new	Real-Time Make-Whole Payment – Lost Cost for Energy (RT_MWP - RT_ELC)	MR Ch.9 ss.3.5.6.1, 3.5.9 and 3.5.10	Dispatchable Generation Resources that are not Pseudo-Units and Dispatchable Electricity Storage Resources that are Registered to Inject $$RT\_ELC_{k,h}^{m,t} = -1\ x\ [[OP(RT\_LMP_h^{m,t}, Max(DAM\_QSI_{k,h}^m, Min(RT\_QSI_{k,h}^{m,t}, AQEI_{k,h}^{m,t})), BE_{k,h}^{m,t})$$ $$- OP(RT\_LMP_h^{m,t}, Max(RT\_LC\_EOP_{k,h}^{m,t}, DAM\_QSI_{k,h}^m), BE_{k,h}^{m,t})] - RT\_FROP\_LC_{k,h}^{m,t}]]/12$$ Where: the disptachable generation resource is registered as a hydroelectric generation resource, $RT\_QSI_{k,h}^{m,t}$ is greater than $FR\_LL_k^{m,f}$, and $RT\_QSI_{k,h}^{m,t}$ is less than or equal to $FR\_UL_k^{m,f}$, then $$RT\_FROP\_LC_{k,h}^{m,t} = OP(RT\_LMP_h^{m,t}, Max(DAM\_QSI_{k,h}^m, Min(RT\_QSI_{k,h}^{m,t}, AQEI_{k,h}^{m,t})), BE_{k,h}^{m,t})$$ $$- OP(RT\_LMP_h^{m,t}, Max(FR\_LL_{k,h}^{m,f}, DAM\_QSI_{k,h}^m, RT\_LC\_EOP_{k,h}^{m,t}), BE_{k,h}^{m,t})$$ Where: $FR\_UL_k^{m,f}$ = the forbidden region upper limit from forbidden region set 'f' where $RT\_QSI_{k,h}^{m,t} <= FR\_UL_k^{m,f}$, as submitted by market participant 'k' for delivery point 'm' as daily dispatch data; $FR\_LL_k^{m,f}$ = the forbidden region lower limit from forbidden region set 'f' where $RT\_QSI_{k,h}^{m,t} > FR\_LL_k^{m,f}$, as submitted by market participant 'k' for delivery point 'm' as daily dispatch data; and f = (1…N) of the forbidden region set $\{FR\_UL_k^{m,f}, F\_LL_k^{m,f}\}$ and N is the maximum number of forbidden regions submitted by market participant 'k' for delivery point 'm' as daily dispatch data. Otherwise $RT\_FROP\_LC_{k,h}^{m,t}$ shall equal zero. Dispatchable Generation Resources that are Pseudo-Units: Combustion Turbine	Interval	Due MP	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			$RT\_ELC_{k,h}^{c,t} = -1 \times \left[OP\left(RT\_LMP_h^{c,t}, Max\left(DAM\_QSI_{k,h}^c, Min\left(RT\_QSI_{k,h}^{c,t}, AQEI_{k,h}^{c,t}\right)\right), RT\_DIPC_{k,h}^{c,t}\right) - OP\left(RT\_LMP_h^{c,t}, Max\left(RT\_LC\_EOP_{k,h}^{c,t}, DAM\_QSI_{k,h}^c\right), RT\_DIPC_{k,h}^{c,t}\right)\right]/12$ Dispatchable Generation Resources that are Pseudo-Units: Steam Turbine $RT\_ELC_{k,h}^{s,t} = -1 \times \left[OP\left(RT\_LMP_h^{s,t}, Max\left(DAM\_DIGQ_{k,h}^s, Min\left(RT\_QSI\_DIGQ_{k,h}^{s,t}, AQEI_{k,h}^{s,t}\right)\right), RT\_DIPC_{k,h}^{s,t}\right) - OP\left(RT\_LMP_h^{s,t}, Max\left(RT\_LC\_EOP\_DIGQ_{k,h}^{s,t}, DAM\_DIGQ_{k,h}^s\right), RT\_DIPC_{k,h}^{s,t}\right)\right]/12$						
1900 MRP new	Real-Time Make-Whole Payment – Lost Cost for Energy (RT_MWP – RT_ELC)	MR Ch.9 s.3.5.7	Dispatchable Loads and Dispatchable Electricity Storage Resources that are Registered to Withdraw $RT\_ELC_{k,h}^{m,t} = \left[OP\left(RT\_LMP_h^{m,t}, Max\left(DAM\_QSW_{k,h}^m, Min\left(RT\_QSW_{k,h}^{m,t}, AQEW_{k,h}^{m,t}\right)\right), BL_{k,h}^{m,t}\right) - OP\left(RT\_LMP_h^{m,t}, Max\left(RT\_LC\_EOP_{k,h}^{m,t}, DAM\_QSW_{k,h}^m\right), BL_{k,h}^{m,t}\right)\right]/12$	Interval	Due MP	13	N/A	N/A	N/A	
1900 MRP new	Real-Time Make-Whole Payment – Lost Cost for Energy (RT_MWP – RT_ELC)	MR Ch.9 s.3.5.8	Boundary Entity Resources – Exports Export transaction dispatched with a reason code associated with manual dispatch out-of-merit: $RT\_ELC_{k,h}^{i,t} = \{ OP\left(RT\_LMP_h^{i,t}, Max\left(SQEW_{k,h}^{i,t}, DAM\_QSW_{k,h}^i\right), BL_{k,h}^{i,t}\right) - OP\left(RT\_LMP_h^{i,t}, Max\left(RT\_LC\_EOP_{k,h}^{i,t}, DAM\_QSW_{k,h}^i\right), BL_{k,h}^{i,t}\right)\}/12$ Export transaction dispatched with a reason code associated with a pre-dispatch pricing discrepancy: $RT\_ELC_{k,h}^{i,t} = \{ OP\left(Min\left(RT\_LMP_h^{i,t}, PD\_LMP_h^i\right), Max\left(SQEW_{k,h}^{i,t}, DAM\_QSW_{k,h}^i\right), BL_{k,h}^{i,t}\right) - OP\left(Min\left(RT\_LMP_h^{i,t}, PD\_LMP_h^i\right), Max\left(RT\_LC\_EOP_{k,h}^{i,t}, DAM\_QSW_{k,h}^i\right), BL_{k,h}^{i,t}\right)\}/12$	Interval	Due MP	N/A	N/A	13	13	
1901 MRP new	Real-Time Make-Whole Payment – Lost	MR Ch.9 ss.3.5.6,	Dispatchable Generation Resources that are not Pseudo-Units and Dispatchable Electricity Storage Resources that are Registered to Inject	Interval	Due MP	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
	Cost for 10-Minute Spinning Reserve (RT_MWP – RT_OLC)	3.5.9, and 3.5.10	$RT\_OLC_{k,h}^{m,t} = -1 \times \left[OP\left(RT\_PROR_{r1,h}^{m,t}, Max(DAM\_QSOR_{r1,k,h}^{m}, RT\_QSOR_{r1,k,h}^{m,t}), BOR_{r1,k,h}^{m,t}\right) \right.$ $\left. - OP\left(RT\_PROR_{r1,h}^{m,t}, Max(RT\_OR\_LC\_EOP_{r1,k,h}^{m,t}, DAM\_QSOR_{r1,k,h}^{m}), BOR_{r1,k,h}^{m,t}\right) \right]/12$ Dispatchable Generation Resources that are Pseudo-Units: Combustion Turbine $RT\_OLC_{k,h}^{c,t} = -1 \times \left[OP\left(RT\_PROR_{r1,h}^{c,t}, Max(DAM\_QSOR_{r1,k,h}^{c}, RT\_QSOR_{r1,k,h}^{c,t}), RT\_OR\_DIPC_{r1,k,h}^{c,t}\right) \right.$ $\left. - OP\left(RT\_PROR_{r1,h}^{c,t}, Max(RT\_OR\_LC\_EOP_{r1,k,h}^{c,t}, DAM\_QSOR_{r1,k,h}^{c}), RT\_OR\_DIPC_{r1,k,h}^{c,t}\right) \right]/12$ Dispatchable Generation Resources that are Pseudo-Units: Steam Turbine $RT\_OLC_{k,h}^{s,t} = -1 \times \left[OP\left(RT\_PROR_{r1,h}^{c,t}, Max(DAM\_QSOR_{r1,k,h}^{c}, RT\_QSOR_{r1,k,h}^{c,t}), RT\_OR\_DIPC_{r1,k,h}^{c,t}\right) \right.$ $\left. - OP\left(RT\_PROR_{r1,h}^{c,t}, Max(RT\_OR\_LC\_EOP_{r1,k,h}^{c,t}, DAM\_QSOR_{r1,k,h}^{c}), RT\_OR\_DIPC_{r1,k,h}^{c,t}\right) \right]/12$							
1901 MRP new	Real-Time Make-Whole Payment – Lost Cost for 10-Minute Spinning Reserve (RT_MWP – RT_OLC)	MR Ch.9 s.3.5.7	Dispatchable Loads and Dispatchable Electricity Storage Resources that are Registered to Withdraw $RT\_OLC_{k,h}^{m,t} = -1 \times \left[OP\left(RT\_PROR_{r1,h}^{m,t}, Max(DAM\_QSOR_{r1,k,h}^{m}, RT\_QSOR_{r1,k,h}^{m,t}), BOR_{r1,k,h}^{m,t}\right) \right.$ $\left. - OP\left(RT\_PROR_{r1,h}^{m,t}, Max(RT\_OR\_LC\_EOP_{r1,k,h}^{m,t}, DAM\_QSOR_{r1,k,h}^{m}), BOR_{r1,k,h}^{m,t}\right) \right]/12$	Interval	Due MP	13	N/A	N/A	N/A	
1902 MRP new	Real-Time Make-Whole Payment – Lost Cost for 10-Minute Non-Spinning Reserve	MR Ch.9 ss.3.5.6, 3.5.9, and 3.5.10	Dispatchable Generation Resources that are not Pseudo-Units and Dispatchable Electricity Storage Resources that are Registered to Inject $RT\_OLC_{k,h}^{m,t} = -1 \times \left[OP\left(RT\_PROR_{r2,h}^{m,t}, Max(DAM\_QSOR_{r2,k,h}^{m}, RT\_QSOR_{r2,k,h}^{m,t}), BOR_{r2,k,h}^{m,t}\right) \right.$ $\left. - OP\left(RT\_PROR_{r2,h}^{m,t}, Max(RT\_OR\_LC\_EOP_{r2,k,h}^{m,t}, DAM\_QSOR_{r2,k,h}^{m}), BOR_{r2,k,h}^{m,t}\right) \right]/12$	Interval	Due MP	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
	(RT_MWP – RT_OLC)		Dispatchable Generation Resources that are Pseudo-Units: Combustion Turbine $$RT\_OLC_{k,h}^{c,t} = -1 \times \big[OP\big(RT\_PROR_{r2,h}^{c,t}, Max(DAM\_QSOR_{r2,k,h}^c, RT\_QSOR_{r2,k,h}^{c,t}), RT\_OR\_DIPC_{r2,k,h}^{c,t}\big)$$ $$- OP\big(RT\_PROR_{r2,h}^{c,t}, Max(RT\_OR\_LC\_EOP_{r2,k,h}^{c,t}, DAM\_QSOR_{r2,k,h}^c), RT\_OR\_DIPC_{r2,k,h}^{c,t}\big)\big]$$ $$/12$$ Dispatchable Generation Resources that are Pseudo-Units: Steam Turbine $$RT\_OLC_{k,h}^{s,t} = -1 \times \big[OP\big(RT\_PROR_{r2,h}^{c,t}, Max(DAM\_QSOR_{r2,k,h}^c, RT\_QSOR_{r2,k,h}^{c,t}), RT\_OR\_DIPC_{r2,k,h}^{c,t}\big)$$ $$- OP\big(RT\_PROR_{r2,h}^{c,t}, Max(RT\_OR\_LC\_EOP_{r2,k,h}^{c,t}, DAM\_QSOR_{r2,k,h}^c), RT\_OR\_DIPC_{r2,k,h}^{c,t}\big)\big]$$ $$/12$$						
1902 MRP new	Real-Time Make-Whole Payment – Lost Cost for 10-Minute Non-Spinning Reserve (RT_MWP – RT_OLC)	MR Ch.9 s.3.5.7	Dispatchable Loads and Dispatchable Electricity Storage Resources that are Registered to Withdraw $$RT\_OLC_{k,h}^{m,t} = -1 \times \big[OP\big(RT\_PROR_{r2,h}^{m,t}, Max(DAM\_QSOR_{r2,k,h}^m, RT\_QSOR_{r2,k,h}^{m,t}), BOR_{r2,k,h}^{m,t}\big)$$ $$- OP\big(RT\_PROR_{r2,h}^{m,t}, Max(RT\_OR\_LC\_EOP_{r2,k,h}^{m,t}, DAM\_QSOR_{r2,k,h}^m), BOR_{r2,k,h}^{m,t}\big)\big]/12$$	Interval	Due MP	13	N/A	N/A	N/A	
1902 MRP new	Real-Time Make-Whole Payment – Lost Cost for 10-Minute Non-Spinning Reserve (RT_MWP – RT_OLC)	MR Ch.9 s.3.5.8	Boundary Entity Resources – Exports Export transaction dispatched with a reason code associated with manual dispatch out-of-merit: $$RT\_OLC_{k,h}^{i,t} = -1 \times \big\{ OP\big(RT\_PROR_{r2,h}^{i,t}, Max(RT\_QSOR_{r2,k,h}^{i,t}, DAM\_QSOR_{r2,k,h}^i), BOR_{r2,k,h}^{i,t}\big)$$ $$- OP\big(RT\_PROR_{r2,h}^{i,t}, Max(RT\_OR\_LC\_EOP_{r2,k,h}^{i,t}, DAM\_QSOR_{r2,k,h}^i), BOR_{r2,k,h}^{i,t}\big)\big\}/12$$ Export transaction dispatched with a reason code associated with a pre-dispatch pricing discrepancy:	Interval	Due MP	N/A	N/A	13	13	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			$$RT\_OLC_{k,h}^{i,t} = -1 \times \left[OP\left(RT\_PROR_{r2,h}^{i,t}, Max(RT\_QSOR_{r2,k,h}^{i,t}, DAM\_QSOR_{r2,k,h}^{i}), BOR_{r2,k,h}^{i,t}\right) - OP\left(RT\_PROR_{r2,h}^{i,t}, Max(RT\_OR\_LC\_EOP_{r2,k,h}^{i,t}, DAM\_QSOR_{r2,k,h}^{i}), BOR_{r2,k,h}^{i,t}\right) \right] / 12$$							
1902 MRP new	Real-Time Make-Whole Payment – Lost Cost for 10-Minute Non-Spinning Reserve (RT_MWP – RT_OLC)	MR Ch.9 s.3.5.8	Boundary Entity Resources – Imports $$RT\_OLC_{k,h}^{i,t} = -1 \times \left[OP\left(RT\_PROR_{r2,h}^{i,t}, Max(RT\_QSOR_{r2,k,h}^{i,t}, DAM\_QSOR_{r2,k,h}^{i}), BOR_{r2,k,h}^{i,t}\right) - OP\left(RT\_PROR_{r2,h}^{i,t}, Max(RT\_OR\_LC\_EOP_{r2,k,h}^{i,t}, DAM\_QSOR_{r2,k,h}^{i}), BOR_{r2,k,h}^{i,t}\right) \right] / 12$$	Interval	Due MP	N/A	13	N/A	N/A	
1903 MRP new	Real-Time Make-Whole Payment – Lost Cost for 30-Minute Operating Reserve (RT_MWP – RT_OLC)	MR Ch.9 ss.3.5.6, 3.5.9, and 3.5.10	Dispatchable Generation Resources that are not Pseudo-Units and Dispatchable Electricity Storage Resources that are Registered to Inject $$RT\_OLC_{k,h}^{m,t} = -1 \times \left[OP\left(RT\_PROR_{r3,h}^{m,t}, Max(DAM\_QSOR_{r3,k,h}^{m}, RT\_QSOR_{r3,k,h}^{m,t}), BOR_{r3,k,h}^{m,t}\right) - OP\left(RT\_PROR_{r3,h}^{m,t}, Max(RT\_OR\_LC\_EOP_{r3,k,h}^{m,t}, DAM\_QSOR_{r3,k,h}^{m}), BOR_{r3,k,h}^{m,t}\right) \right] / 12$$ Dispatchable Generation Resources that are Pseudo-Units: Combustion Turbine $$RT\_OLC_{k,h}^{c,t} = -1 \times \left[OP\left(RT\_PROR_{r3,h}^{c,t}, Max(DAM\_QSOR_{r3,k,h}^{c}, RT\_QSOR_{r3,k,h}^{c,t}), RT\_OR\_DIPC_{r3,k,h}^{c,t}\right) - OP\left(RT\_PROR_{r3,h}^{c,t}, Max(RT\_OR\_LC\_EOP_{r3,k,h}^{c,t}, DAM\_QSOR_{r3,k,h}^{c}), RT\_OR\_DIPC_{r3,k,h}^{c,t}\right) \right] / 12$$ Dispatchable Generation Resources that are Pseudo-Units: Steam Turbine $$RT\_OLC_{k,h}^{s,t} = -1 \times \left[OP\left(RT\_PROR_{r3,h}^{s,t}, Max(DAM\_QSOR_{r3,k,h}^{s}, RT\_QSOR_{r3,k,h}^{s,t}), RT\_OR\_DIPC_{r3,k,h}^{s,t}\right) - OP\left(RT\_PROR_{r3,h}^{s,t}, Max(RT\_OR\_LC\_EOP_{r3,k,h}^{s,t}, DAM\_QSOR_{r3,k,h}^{s}), RT\_OR\_DIPC_{r3,k,h}^{s,t}\right) \right] / 12$$	Interval	Due MP	13	N/A	N/A	N/A	
1903 MRP new	Real-Time Make-Whole Payment – Lost Cost for 30-Minute	MR Ch.9 s.3.5.7	Dispatchable Loads and Dispatchable Electricity Storage Resources that are Registered to Withdraw	Interval	Due MP	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
	Operating Reserve (RT_MWP – RT_OLC)		$RT\_OLC_{k,h}^{m,t} = -1 \times \big[OP\big(RT\_PROR_{r3,h}^{m,t}, Max(DAM\_QSOR_{r3,k,h}^{m}, RT\_QSOR_{r3,k,h}^{m,t}), BOR_{r3,k,h}^{m,t}\big)$ $- OP\big(RT\_PROR_{r3,h}^{m,t}, Max(RT\_OR\_LC\_EOP_{r3,k,h}^{m,t}, DAM\_QSOR_{r3,k,h}^{m}), BOR_{r3,k,h}^{m,t}\big)\big]/12$							
1903 MRP new	Real-Time Make-Whole Payment – Lost Cost for 30-Minute Operating Reserve (RT_MWP – RT_OLC)	MR Ch.9 s.3.5.8	Boundary Entity Resources – Exports Export transaction dispatched with a reason code associated with manual dispatch out-of-merit: $RT\_OLC_{k,h}^{i,t} = -1 \, x \, \big\{OP\big(RT\_PROR_{r3,h}^{i,t}, Max(RT\_QSOR_{r3,k,h}^{i,t}, DAM\_QSOR_{r3,k,h}^{i}), BOR_{r3,k,h}^{i,t}\big)$ $- OP\big(RT\_PROR_{r3,h}^{i,t}, Max(RT\_OR\_LC\_EOP_{r3,k,h}^{i,t}, DAM\_QSOR_{r3,k,h}^{i}), BOR_{r3,k,h}^{i,t}\big)\big\}/12$ Export transaction dispatched with a reason code associated with a pre-dispatch pricing discrepancy: $RT\_OLC_{k,h}^{i,t} = -1 \times \big[OP\big(RT\_PROR_{r3,h}^{i,t}, Max(RT\_QSOR_{r3,k,h}^{i,t}, DAM\_QSOR_{r3,k,h}^{i}), BOR_{r3,k,h}^{i,t}\big)$ $- OP\big(RT\_PROR_{r3,h}^{i,t}, Max(RT\_OR\_LC\_EOP_{r3,k,h}^{i,t}, DAM\_QSOR_{r3,k,h}^{i}), BOR_{r3,k,h}^{i,t}\big)\big] /12$	Interval	Due MP	N/A	N/A	13	13	
1903 MRP new	Real-Time Make-Whole Payment – Lost Cost for 30-Minute Operating Reserve (RT_MWP – RT_OLC)	MR Ch.9 s.3.5.8	Boundary Entity Resources – Imports $RT\_OLC_{k,h}^{i,t} = -1 \times \big[OP\big(RT\_PROR_{r3,h}^{i,t}, Max(RT\_QSOR_{r3,k,h}^{i,t}, DAM\_QSOR_{r3,k,h}^{i}), BOR_{r3,k,h}^{i,t}\big)$ $- OP\big(RT\_PROR_{r3,h}^{i,t}, Max(RT\_OR\_LC\_EOP_{r3,k,h}^{i,t}, DAM\_QSOR_{r3,k,h}^{i}), BOR_{r3,k,h}^{i,t}\big)\big] /12$	Interval	Due MP	N/A	13	N/A	N/A	
1904 MRP new	Real-Time Make-Whole Payment – Lost Opportunity Cost for Energy	MR Ch.9 ss.3.5.6.2, 3.5.9, and 3.5.10	Dispatchable Generation Resources that are not Pseudo-Units and Dispatchable Electricity Storage Resources that are Registered to Inject $RT\_ELOC_{k,h}^{m,t} = \big\{OP\big(RT\_LMP_{h}^{m,t}, RT\_LOC\_EOP_{k,h}^{m,t}, BE_{k,h}^{m,t}\big)$ $- Max\big[0, OP\big(RT\_LMP_{h}^{m,t}, Max(RT\_QSI_{k,h}^{m,t}, AQEI_{k,h}^{m,t}), BE_{k,h}^{m,t}\big)\big] - RT\_FROP\_LOC_{k,h}^{m,t}\big\}/12$ Where:	Interval	Due MP	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
	(RT_MWP − RT_ELOC)		if the dispatchable generation resource is registered as a hydroelectric generation resource, $RT\_QSI_{k,h}^{m,t}$ is greater than $FR\_LL_k^{m,f}$, and $RT\_QSI_{k,h}^{m,t}$ is less than or equal to $FR\_UL_k^{m,f}$, then $$RT\_FROP\_LOC_{k,h}^{m,t} = OP\big(RT\_LMP_h^{m,t}, Min(FR\_UL_{k,h}^{m,f}, RT\_LOC\_EOP_{k,h}^{m,t}), BE_{k,h}^{m,t}\big) \\ - Max\big[0, OP\big(RT\_LMP_h^{m,t}, Max(RT\_QSI_{k,h}^{m,t,f}, AQEI_{k,h}^{m,t}), BE_{k,h}^{m,t}\big)\big]$$ Where: '$FR\_UL_k^{m,f}$' = the forbidden region upper limit from forbidden region set 'f' where $RT\_QSI_{k,h}^m < FR\_UL_k^{m,f}$, as submitted by market participant 'k' for delivery point 'm' as daily dispatch data; '$FR\_LL_k^{m,f}$' = the forbidden region lower limit from forbidden region set 'f' where $RT\_QSI_{k,h}^m >= FR\_LL_k^{m,f}$, as submitted by market participant 'k' for delivery point 'm' as daily dispatch data; and 'f' = (1...N) of the forbidden region set $\{FR\_UL_k^{m,f}, FR\_LL_k^{m,f}\}$ and N is the maximum number of forbidden regions submitted by market participant 'k' for delivery point 'm' as daily dispatch data. Otherwise $RT\_FROP\_LOC_{k,h}^{m,t}$ shall equal zero. Dispatchable Generation Resources that are Pseudo-Units: Combustion Turbine $$RT\_ELOC_{k,h}^{c,t} = \{OP\big(RT\_LMP_h^{c,t}, RT\_LOC\_EOP_{k,h}^{c,t}, RT\_DIPC_{k,h}^{c,t}\big) \\ - Max\big[0, OP\big(RT\_LMP_h^{c,t}, Max(RT\_QSI_{k,h}^{c,t}, AQEI_{k,h}^{c,t}), RT\_DIPC_{k,h}^{c,t}\big)\big]\}/12$$ Dispatchable Generation Resources that are Pseudo-Units: Steam Turbine $$RT\_ELOC_{k,h}^{s,t} = \{OP\big(RT\_LMP_h^{s,t0}, RT\_LOC\_EOP\_DIGQ_{k,h}^{s,t0}, RT\_DIPC_{k,h}^{s,t0}\big) \\ - Max\big[0, OP\big(RT\_LMP_h^{s,t0}, Max(RT\_QSI\_DIGQ_{k,h}^{s,t0}, AQEI_{k,h}^{s,t0}), RT\_DIPC_{k,h}^{s,t0}\big)\big]\}/12 \\ + \{OP\big(RT\_LMP_h^{s,t1}, RT\_LOC\_EOP\_DIGQ_{k,h}^{s,t1}, RT\_DIPC_{k,h}^{s,t1}\big) \\ - Max\big[0, OP\big(RT\_LMP_h^{s,t1}, RT\_QSI\_DIGQ_{k,h}^{s,t1}, RT\_DIPC_{k,h}^{s,t1}\big)\big]\}/12$$ Where: t0 = metering interval 't' in settlement hour "h" when none of the combustion turbine resources associated with the steam turbine resources have a real-time schedule that is less than its respective minimum loading point; and							

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			t1 = metering interval 't' in settlement hour "h" when (1) at least one combustion turbine resource associated with the steam turbine resource has a real-time schedule greater than or equal to its minimum loading point; and (2) at least one of the combustion turbine resources associated with the steam turbine resource has a real-time schedule that is less than its respective minimum loading point. Note: For greater certainty, 't1' and 't0' metering intervals are mutually exclusive, and the calculation will be conducted using either the 't1' or 't0' variables, depending on whether the relevant metering interval meets the criteria of 't1' or 't0', respectively.						
1904 MRP new	Real-Time Make-Whole Payment – Lost Opportunity Cost for Energy (RT_MWP – RT_ELOC)	MR Ch.9 s.3.5.7	Dispatchable Loads and Dispatchable Electricity Storage Resources that are Registered to Withdraw $RT\_ELOC_{k,h}^{m,t} = -1 \times \{OP(RT\_LMP_h^{m,t}, RT\_LOC\_EOP_{k,h}^{m,t}, BL_{k,h}^{m,t})$ $- OP(RT\_LMP_h^{m,t}, Max(RT\_QSW_{k,h}^{m,t}, AQEW_{k,h}^{m,t}), BL_{k,h}^{m,t})\}/12$	Interval	Due MP	13	N/A	N/A	N/A	
1905 MRP new	Real-Time Make-Whole Payment – Lost Opportunity Cost for 10-Minute Spinning Reserve (RT_MWP – RT_OLOC)	MR Ch.9 ss.3.5.6, 3.5.9, and 3.5.10	Dispatchable Generation Resources that are not Pseudo-Units and Dispatchable Electricity Storage Resources that are Registered to Inject $RT\_OLOC_{k,h}^{m,t} = \{OP(RT\_PROR_{r1,h}^{m,t}, RT\_OR\_LOC\_EOP_{r1,k,h}^{m,t}, BOR_{r1,k,h}^{m,t})$ $- Max[0, OP(RT\_PROR_{r1,h}^{m,t}, RT\_QSOR_{r1,k,h}^{m,t}, BOR_{r1,k,h}^{m,t})]\}/12$ Dispatchable Generation Resources that are Pseudo-Units: Combustion Turbine $RT\_OLOC_{k,h}^{c,t} = \left[OP(RT\_PROR_{r1,h}^{c,t}, RT\_OR\_LOC\_EOP_{r1,k,h}^{c,t}, RT\_OR\_DIPC_{r1,k,h}^{c,t})\right.$ $\left. - Max[0, OP(RT\_PROR_{r1,h}^{c,t}, RT\_QSOR_{r1,k,h}^{c,t}, RT\_OR\_DIPC_{r1,k,h}^{c,t})]\right]/12$ Dispatchable Generation Resources that are Pseudo-Units: Steam Turbine	Interval	Due MP	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			$$RT\_OLOC_{k,h}^{s} = \{OP(RT\_PROR_{r1,h}^{s,t}, RT\_OR\_LOC\_EOP_{r1,k,h}^{s,t}, RT\_OR\_DIPC_{r1,k,h}^{s,t})$$ $$- Max[0, OP(RT\_PROR_{r1,h}^{s,t}, RT\_QSOR_{r1,k,h}^{s,t}, RT\_OR\_DIPC_{r1,k,h}^{s,t})]\}/12$$							
1905 MRP new	Real-Time Make-Whole Payment – Lost Opportunity Cost for 10-Minute Spinning Reserve (RT_MWP – RT_OLOC)	MR Ch.9 s.3.5.7	Dispatchable Loads and Dispatchable Electricity Storage Resources that are Registered to Withdraw $$RT\_OLOC_{k,h}^{m,t} = \{OP(RT\_PROR_{r1,h}^{m,t}, RT\_OR\_LOC\_EOP_{r1,k,h}^{m,t}, BOR_{r1,k,h}^{m,t})$$ $$- Max[0, OP(RT\_PROR_{r1,h}^{m,t}, RT\_QSOR_{r1,k,h}^{m,t}, BOR_{r1,k,h}^{m,t})]\}/12$$	Interval	Due MP	13	N/A	N/A	N/A	
1906 MRP new	Real-Time Make-Whole Payment – Lost Opportunity Cost for 10-Minute Non-Spinning Reserve (RT_MWP – RT_OLOC)	MR Ch.9 ss.3.5.6, 3.5.9, and 3.5.10	Dispatchable Generation Resources that are not Pseudo-Units and Dispatchable Electricity Storage Resources that are Registered to Inject $$RT\_OLOC_{k,h}^{m,t} = \{OP(RT\_PROR_{r2,h}^{m,t}, RT\_OR\_LOC\_EOP_{r2,k,h}^{m,t}, BOR_{r2,k,h}^{m,t})$$ $$- Max[0, OP(RT\_PROR_{r2,h}^{m,t}, RT\_QSOR_{r2,k,h}^{m,t}, BOR_{r2,k,h}^{m,t})]\}/12$$ Dispatchable Generation Resources that are Pseudo-Units: Combustion Turbine $$RT\_OLOC_{k,h}^{c,t} = \left[OP(RT\_PROR_{r2,h}^{c,t}, RT\_OR\_LOC\_EOP_{r2,k,h}^{c,t}, RT\_OR\_DIPC_{r2,k,h}^{c,t})\right.$$ $$\left. - Max[0, OP(RT\_PROR_{r2,h}^{c,t}, RT\_QSOR_{r2,k,h}^{c,t}, RT\_OR\_DIPC_{r2,k,h}^{c,t})]\right]/12$$ Dispatchable Generation Resources that are Pseudo-Units: Steam Turbine $$RT\_OLOC_{k,h}^{s} = \{OP(RT\_PROR_{r2,h}^{s,t}, RT\_OR\_LOC\_EOP_{r2,k,h}^{s,t}, RT\_OR\_DIPC_{r2,k,h}^{s,t})$$ $$- Max[0, OP(RT\_PROR_{r2,h}^{s,t}, RT\_QSOR_{r2,k,h}^{s,t}, RT\_OR\_DIPC_{r2,k,h}^{s,t})]\}/12$$	Interval	Due MP	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
1906 MRP new	Real-Time Make-Whole Payment – Lost Opportunity Cost for 10-Minute Non-Spinning Reserve (RT_MWP – RT_OLOC)	MR Ch.9 s.3.5.7	Dispatchable Loads and Dispatchable Electricity Storage Resources that are Registered to Withdraw $$RT\_OLOC_{k,h}^{m,t} = \{OP(RT\_PROR_{r2,h}^{m,t}, RT\_OR\_LOC\_EOP_{r2,k,h}^{m,t}, BOR_{r2,k,h}^{m,t}) - Max[0, OP(RT\_PROR_{r2,h}^{m,t}, RT\_QSOR_{r2,k,h}^{m,t}, BOR_{r2,k,h}^{m,t})]\}/12$$	Interval	Due MP	13	N/A	N/A	N/A	
1907 MRP new	Real-Time Make-Whole Payment – Lost Opportunity Cost for 30-Minute Operating Reserve (RT_MWP – RT_OLOC)	MR Ch.9 ss.3.5.6, 3.5.9, and 3.5.10	Dispatchable Generation Resources that are not Pseudo-Units and Dispatchable Electricity Storage that are Registered to Inject $$RT\_OLOC_{k,h}^{m,t} = \{OP(RT\_PROR_{r3,h}^{m,t}, RT\_OR\_LOC\_EOP_{r3,k,h}^{m,t}, BOR_{r3,k,h}^{m,t}) - Max[0, OP(RT\_PROR_{r3,h}^{m,t}, RT\_QSOR_{r3,k,h}^{m,t}, BOR_{r3,k,h}^{m,t})]\}/12$$ Dispatchable Generation Resources that are Pseudo-Units: Combustion Turbine $$RT\_OLOC_{k,h}^{c,t} = \left[OP(RT\_PROR_{r3,h}^{c,t}, RT\_OR\_LOC\_EOP_{r3,k,h}^{c,t}, RT\_OR\_DIPC_{r3,k,h}^{c,t}) - Max[0, OP(RT\_PROR_{r3,h}^{c,t}, RT\_QSOR_{r3,k,h}^{c,t}, RT\_OR\_DIPC_{r3,k,h}^{c,t})] \right]/12$$ Dispatchable Generation Resources that are Pseudo-Units: Steam Turbine $$RT\_OLOC_{k,h}^{s} = \{OP(RT\_PROR_{r3,h}^{s,t}, RT\_OR\_LOC\_EOP_{r3,k,h}^{s,t}, RT\_OR\_DIPC_{r3,k,h}^{s,t}) - Max[0, OP(RT\_PROR_{r3,h}^{s,t}, RT\_QSOR_{r3,k,h}^{s,t}, RT\_OR\_DIPC_{r3,k,h}^{s,t})]\}/12$$	Interval	Due MP	13	N/A	N/A	N/A	
1907 MRP new	Real-Time Make-Whole Payment – Lost Opportunity Cost for 30-Minute	MR Ch.9 s.3.5.7	Dispatchable Loads and Dispatchable Electricity Storage Resources that are Registered to Withdraw $$RT\_OLOC_{k,h}^{m,t} = \{OP(RT\_PROR_{r3,h}^{m,t}, RT\_OR\_LOC\_EOP_{r3,k,h}^{m,t}, BOR_{r3,k,h}^{m,t}) - Max[0, OP(RT\_PROR_{r3,h}^{m,t}, RT\_QSOR_{r3,k,h}^{m,t}, BOR_{r3,k,h}^{m,t})]\}/12$$	Interval	Due MP	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
	Operating Reserve (RT_MWP − RT_OLOC)									

1908
MRP new
	Real-Time Make-Whole Payment - Operating Reserve Non-Accessibility Lost Cost Reversal
	
	(RT_MWP - RT_OLC_RC)
		MRs Ch.9 ss.3.10.2, 3.10.4, 3.10.5, 3.10.18, 3.10.21, 3.10.24	Dispatchable Loads, Dispatchable Electricity Storage Resources, and Dispatchable Generation Resources that are not Pseudo-Units
			
			$$RT\_OLC\_RC_{k,h}^{m,t} = Min\left[0, Max\left(-1 \times \left(RT\_ELC_{k,h}^{m,t} + RT\_OLC_{k,h}^{m,t}\right), \sum_R OLC\_CB_{r,k,h}^{m,t}\right)\right]$$
			
			Where:
			a. For synchronized *ten-minute operating reserve*:
			  i. if $TAOR_{k,h}^{m,t} < RT\_QSOR_{r1,k,h}^{m,t}$ and if $RT\_OR\_LC\_EOP_{r1,k,h}^{m,t} < RT\_QSOR_{r1,k,h}^{m,t}$ then:
			
			$$OLC\_CB_{r1,k,h}^{m,t} = \{OP\left(RT\_PROR_{r1,h}^{m,t}, Max(DAM\_QSOR_{r1,k,h}^{m,t}, RT\_QSOR_{r1,k,h}^{m,t}), BOR_{r1,k,h}^{m,t}\right) - OP\left[RT\_PROR_{r1,h}^{m,t}, Max\left(TAOR_{k,h}^{m,t}, RT\_OR\_LC\_EOP_{r1,k,h}^{m,t}, DAM\_QSOR_{r1,k,h}^{m,t}\right), BOR_{r1,k,h}^{m,t}\right]/12$$
			
			  ii. otherwise, $OLC\_CB_{r1,k,h}^{m,t} = 0$
			
			b. For non-synchronized *ten-minute operating reserve*:
			  i. if $TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t} < RT\_QSOR_{r2,k,h}^{m,t}$ and if $RT\_OR\_LC\_EOP_{r2,k,h}^{m,t} < RT\_QSOR_{r2,k,h}^{m,t}$, then:
			
			$$OLC\_CB_{r2,k,h}^{m,t} = \{OP\left(RT\_PROR_{r2,h}^{m,t}, Max(DAM\_QSOR_{r2,k,h}^{m,t}, RT\_QSOR_{r2,k,h}^{m,t}), BOR_{r2,k,h}^{m,t}\right) - OP\left[RT\_PROR_{r2,h}^{m,t}, Max\left(TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t}, RT\_OR\_LC\_EOP_{r2,k,h}^{m,t}, DAM\_QSOR_{r2,k,h}^{m,t}\right), BOR_{r2,k,h}^{m,t}\right]/12$$
			
			  ii. otherwise, $OLC\_CB_{r2,k,h}^{m,t} = 0$
				Interval	Due IESO	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			c. For *thirty-minute operating reserve*: i. if $TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t} - RT\_QSOR_{r2,k,h}^{m,t} < RT\_QSOR_{r3,k,h}^{m,t}$ and if $RT\_OR\_LC\_EOP_{r3,k,h}^{m,t} < RT\_QSOR_{r3,k,h}^{m,t}$, then: $OLC\_CB_{r3,k,h}^{m,t} = \{OP(RT\_PROR_{r3,h}^{m,t}, Max(DAM\_QSOR_{r3,k,h}^{m,t}, RT\_QSOR_{r3,k,h}^{m,t}), BOR_{r3,k,h}^{m,t}) - OP[RT\_PROR_{r3,h}^{m,t}, Max(TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t} - RT\_QSOR_{r2,k,h}^{m,t}, RT\_OR\_LC\_EOP_{r3,k,h}^{m,t}, DAM\_QSOR_{r3,k,h}^{m,t}), BOR_{r3,k,h}^{m,t}]/12$ ii. otherwise, $OLC\_CB_{r3,k,h}^{m,t} = 0$ Dispatchable Generation Resources that are Pseudo-Units Combustion turbine resource: $RT\_OLC\_RC_{k,h}^{c,t} = Min\left[0, Max\left(-1 \, x \, (RT\_ELC_{k,h}^{c,t} + RT\_OLC_{k,h}^{c,t}), \sum_{R} OLC\_CB_{r,k,h}^{c,t}\right)\right]$ Where: a. For synchronized *ten-minute operating reserve*: i. if $TAOR\_CT_{k,h}^{c,t} < RT\_QSOR_{r1,k,h}^{c,t}$ and if $RT\_OR\_LC\_EOP_{r1,k,h}^{c,t} < RT\_QSOR_{r1,k,h}^{c,t}$ then: $OLC\_CB_{r1,k,h}^{c,t} = \{OP\left(RT\_PROR_{r1,h}^{c,t}, Max(DAM\_QSOR_{r1,k,h}^{c,t}, RT\_QSOR_{r1,k,h}^{c,t}), RT\_OR\_DIPC_{r1,k,h}^{c,t}\right) - OP\left[RT\_PROR_{r1,h}^{c,t}, Max\left(TAOR\_CT_{k,h}^{c,t}, RT\_OR\_LC\_EOP_{r1,k,h}^{c,t}, DAM\_QSOR_{r1,k,h}^{c,t}\right), RT\_OR\_DIPC_{r1,k,h}^{c,t}\right]/12$ ii. otherwise, $OLC\_CB_{r1,k,h}^{c,t} = 0$							

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			b. For non-synchronized *ten-minute operating reserve*: i. if $TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t} < RT\_QSOR_{r2,k,h}^{c,t}$ and if $RT\_OR\_LC\_EOP_{r2,k,h}^{c,t} < RT\_QSOR_{r2,k,h}^{c,t}$, then: $OLC\_CB_{r2,k,h}^{c,t} =$ $\{OP\left(RT\_PROR_{r2,h}^{c,t}, Max(DAM\_QSOR_{r2,k,h}^{c,t}, RT\_QSOR_{r2,k,h}^{c,t}), RT\_OR\_DIPC_{r2,k,h}^{c,t}\right) -$ $OP\left[RT\_PROR_{r2,h}^{c,t}, Max\left(TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t}, RT\_OR\_LC\_EOP_{r2,k,h}^{c,t}, DAM\_QSOR_{r2,k,h}^{c,t}\right), RT\_OR\_DIPC_{r2,k,h}^{c,t}\right]/12$ ii. otherwise, $OLC\_CB_{r2,k,h}^{c,t} = 0$ c. For *thirty-minute operating reserve*: i. if $TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t} - RT\_QSOR_{r2,k,h}^{c,t} < RT\_QSOR_{r3,k,h}^{c,t}$ and if $RT\_OR\_LC\_EOP_{r3,k,h}^{c,t} < RT\_QSOR_{r3,k,h}^{c,t}$, then: $OLC\_CB_{r3,k,h}^{c,t} = \{OP\left(RT\_PROR_{r3,h}^{c,t}, Max(DAM\_QSOR_{r3,k,h}^{c,t}, RT\_QSOR_{r3,k,h}^{c,t}), RT\_OR\_DIPC_{r3,k,h}^{c,t}\right) -$ $OP\left[RT\_PROR_{r3,h}^{c,t}, Max\left(TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t} - RT\_QSOR_{r2,k,h}^{c,t}, RT\_OR\_LC\_EOP_{r3,k,h}^{c,t}, DAM\_QSOR_{r3,k,h}^{c,t}\right), RT\_OR\_DIPC_{r3,k,h}^{c,t}\right]/12$ ii. otherwise, $OLC\_CB_{r3,k,h}^{c,t} = 0$ Steam turbine resource: $RT\_OLC\_RC_{k,h}^{s,t} = Min\left[0, Max\left(-1 \times (RT\_ELC_{k,h}^{s,t} + RT\_OLC_{k,h}^{s,t}), \sum_R OLC\_CB_{r,k,h}^{s,t}\right)\right]$ Where: For synchronized ten-minute operating reserve: if $TAOR\_ST_{k,h}^{s,t} < RT\_QSOR_{r1,k,h}^{s,t}$ and if							

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			$RT\_OR\_LC\_EOP_{r1,k,h}^{s,t} < RT\_QSOR_{r1,k,h}^{s,t}$ then: $OLC\_CB_{r1,k,h}^{s,t} = \{OP\left(RT\_PROR_{r1,h}^{s,t}, Max(DAM\_QSOR_{r1,k,h}^{s,t}, RT\_QSOR_{r1,k,h}^{s,t}), RT\_OR\_DIPC_{r1,k,h}^{s,t}\right) -$ $OP\left[RT\_PROR_{r1,h}^{s,t}, Max\left(TAOR\_ST_{k,h}^{s,t}, RT\_OR\_LC\_EOP_{r1,k,h}^{s,t}, DAM\_QSOR_{r1,k,h}^{s,t}\right), RT\_OR\_DIPC_{r1,k,h}^{s,t}\right]/12$ otherwise, $OLC\_CB_{r1,k,h}^{s,t} = 0$ For non-synchronized ten-minute operating reserve: if $TAOR\_ST_{k,h}^{s,t} - RT\_QSOR_{r1,k,h}^{s,t} < RT\_QSOR_{r2,k,h}^{s,t}$ and if $RT\_OR\_LC\_EOP_{r2,k,h}^{s,t} < RT\_QSOR_{r2,k,h}^{s,t}$, then: $OLC\_CB_{r2,k,h}^{s,t} =$ $\{OP\left(RT\_PROR_{r2,h}^{s,t}, Max(DAM\_QSOR_{r2,k,h}^{s,t}, RT\_QSOR_{r2,k,h}^{s,t}), RT\_OR\_DIPC_{r2,k,h}^{s,t}\right) -$ $OP\left[RT\_PROR_{r2,h}^{s,t}, Max\left(TAOR\_ST_{k,h}^{s,t} - \right.\right.$ $\left.\left. RT\_QSOR_{r1,k,h}^{s,t}, RT\_OR\_LC\_EOP_{r2,k,h}^{s,t}, DAM\_QSOR_{r2,k,h}^{s,t}\right), RT\_OR\_DIPC_{r2,k,h}^{s,t}\right]/12$ otherwise, $OLC\_CB_{r2,k,h}^{s,t} = 0$ For thirty-minute operating reserve: if $TAOR\_ST_{k,h}^{s,t} - RT\_QSOR_{r1,k,h}^{s,t} - RT\_QSOR_{r2,k,h}^{s,t} < RT\_QSOR_{r3,k,h}^{s,t}$ and if $RT\_OR\_LC\_EOP_{r3,k,h}^{s,t} < RT\_QSOR_{r3,k,h}^{s,t}$, then: $OLC\_CB_{r3,k,h}^{s,t} =$ $\{OP\left(RT\_PROR_{r3,h}^{s,t}, Max(DAM\_QSOR_{r3,k,h}^{s,t}, RT\_QSOR_{r3,k,h}^{s,t}), RT\_OR\_DIPC_{r3,k,h}^{s,t}\right) -$ $OP\left[RT\_PROR_{r3,h}^{s,t}, Max\left(TAOR\_ST_{k,h}^{s,t} - RT\_QSOR_{r1,k,h}^{s,t} - \right.\right.$ $\left.\left. RT\_QSOR_{r2,k,h}^{s,t}, RT\_OR\_LC\_EOP_{r3,k,h}^{s,t}, DAM\_QSOR_{r3,k,h}^{s,t}\right), RT\_OR\_DIPC_{r3,k,h}^{s,t}\right]/12$ otherwise, $OLC\_CB_{r3,k,h}^{s,t} = 0$						

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments

1909 MRP new	Real-Time Make-Whole Payment - Operating Reserve Non-Accessibility Lost Opportunity Cost Reversal
	
	(RT_MWP - RT_OLOC_RC)
		MRs Ch.9 ss.3.10.2, 3.10.4, 3.10.5, 3.10.19, 3.10.22, 3.10.25	Dispatchable Loads, Dispatchable Electricity Storage Resources and Dispatchable Generation Resources that are not Pseudo-Units
			
			$$RT\_OLOC\_RC_{k,h}^{m,t} = Min\left[0, Max\left(-1 \; x \; (RT\_ELOC_{k,h}^{m,t} + RT\_OLOC_{k,h}^{m,t}), \sum_{R} OLOC\_CB_{r,k,h}^{m,t}\right)\right]$$
			
			Where:
			
			a. For synchronized *ten-minute operating reserve*:
			
			  i. if $TAOR_{k,h}^{m,t} < RT\_OR\_LOC\_EOP_{r1,k,h}^{m,t}$ and if $RT\_QSOR_{r1,k,h}^{m,t} < RT\_OR\_LOC\_EOP_{r1,k,h}^{m,t}$ then:
			
			$$OLOC\_CB_{r1,k,h}^{m,t} = (-1) \times \left\{OP\left(RT\_PROR_{r1,h}^{m,t}, RT\_OR\_LOC\_EOP_{r1,k,h}^{m,t}, BOR_{r1,k,h}^{m,t}\right) - OP\left[RT\_PROR_{r1,h}^{m,t}, Max\left(RT\_QSOR_{r1,k,h}^{m,t}, TAOR_{k,h}^{m,t}\right), BOR_{r1,k,h}^{m,t}\right]\right\}/12$$
			
			  ii. otherwise, $OLOC\_CB_{r1,k,h}^{m,t} = 0$
			
			b. For non-synchronized *ten-minute operating reserve*:
			
			  i. if $TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t} < RT\_OR\_LOC\_EOP_{r2,k,h}^{m,t}$ and if $RT\_QSOR_{r2,k,h}^{m,t} < RT\_OR\_LOC\_EOP_{r2,k,h}^{m,t}$, then:
			
			$$OLOC\_CB_{r2,k,h}^{m,t} = (-1) \times \left\{OP\left(RT\_PROR_{r2,h}^{m,t}, RT\_OR\_LOC\_EOP_{r2,k,h}^{m,t}, BOR_{r2,k,h}^{m,t}\right) - OP\left[RT\_PROR_{r2,h}^{m,t}, Max\left(RT\_QSOR_{r2,k,h}^{m,t}, TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t}\right), BOR_{r2,k,h}^{m,t}\right]\right\}/12$$
			
			  ii. otherwise, $OLOC\_CB_{r2,k,h}^{m,t} = 0$
				Interval	Due IESO	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			c. For *thirty-minute operating reserve*: i. if $TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t} - RT\_QSOR_{r2,k,h}^{m,t} < RT\_OR\_LOC\_EOP_{r3,k,h}^{m,t}$ and if $RT\_QSOR_{r3,k,h}^{m,t} < RT\_OR\_LOC\_EOP_{r3,k,h}^{m,t}$, then: $OLOC\_CB_{r3,k,h}^{m,t} = (-1) \times \{OP(RT\_PROR_{r3,h}^{m,t}, RT\_OR\_LOC\_EOP_{r3,k,h}^{m,t}, BOR_{r3,k,h}^{m,t}) - OP[RT\_PROR_{r3,h}^{m,t}, Max(RT\_QSOR_{r3,k,h}^{m,t}, TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t} - RT\_QSOR_{r2,k,h}^{m,t}), BOR_{r3,k,h}^{m,t}]\}/12$ ii. otherwise, $OLOC\_CB_{r3,k,h}^{m,t} = 0$ Dispatchable Generation Resources that are Pseudo-Units Combustion turbine resource: $RT\_OLOC\_RC_{k,h}^{c,t} = Min\left[0, Max\left(-1 \times \left(RT\_ELOC_{k,h}^{c,t} + RT\_OLOC_{k,h}^{c,t}\right), \sum_R OLOC\_CB_{r,k,h}^{c,t}\right)\right]$ Where: a. For synchronized *ten-minute operating reserve*: i. if $TAOR\_CT_{k,h}^{c,t} < RT\_OR\_LOC\_EOP_{r1,k,h}^{c,t}$ and if $RT\_QSOR_{r1,k,h}^{c,t} < RT\_OR\_LOC\_EOP_{r1,k,h}^{c,t}$ then: $OLOC\_CB_{r1,k,h}^{c,t} = (-1) \times \{OP(RT\_PROR_{r1,h}^{c,t}, RT\_OR\_LOC\_EOP_{r1,k,h}^{c,t}, RT\_OR\_DIPC_{r1,k,h}^{c,t}) - OP[RT\_PROR_{r1,h}^{c,t}, Max(RT\_QSOR_{r1,k,h}^{c,t}, TAOR\_CT_{k,h}^{c,t}), RT\_OR\_DIPC_{r1,k,h}^{c,t}]\}/12$ ii. otherwise, $OLOC\_CB_{r1,k,h}^{c,t} = 0$						

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			b. For non-synchronized *ten-minute operating reserve*: i. if $TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t} < RT\_OR\_LOC\_EOP_{r2,k,h}^{c,t}$ and if $RT\_QSOR_{r2,k,h}^{c,t} < RT\_OR\_LOC\_EOP_{r2,k,h}^{c,t}$, then: $OLOC\_CB_{r2,k,h}^{c,t} = (-1) \times \{OP(RT\_PROR_{r2,h}^{c,t}, RT\_OR\_LOC\_EOP_{r2,k,h}^{c,t}, RT\_OR\_DIPC_{r2,k,h}^{c,t}) - OP[RT\_PROR_{r2,h}^{c,t}, Max(RT\_QSOR_{r2,k,h}^{c,t}, TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t}), RT\_OR\_DIPC_{r2,k,h}^{c,t}]\}/12$ ii. otherwise, $OLOC\_CB_{r2,k,h}^{c,t} = 0$ c. For *thirty-minute operating reserve*: i. if $TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t} - RT\_QSOR_{r2,k,h}^{c,t} < RT\_OR\_LOC\_EOP_{r3,k,h}^{c,t}$ and if $RT\_QSOR_{r3,k,h}^{c,t} < RT\_OR\_LOC\_EOP_{r3,k,h}^{c,t}$, then: $OLOC\_CB_{r3,k,h}^{c,t} = (-1) \times \{OP(RT\_PROR_{r3,h}^{c,t}, RT\_OR\_LOC\_EOP_{r3,k,h}^{c,t}, RT\_OR\_DIPC_{r3,k,h}^{c,t}) - OP[RT\_PROR_{r3,h}^{c,t}, Max(RT\_QSOR_{r3,k,h}^{c,t}, TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t} - RT\_QSOR_{r2,k,h}^{c,t}), RT\_OR\_DIPC_{r3,k,h}^{c,t}]\}/12$ ii. otherwise, $OLOC\_CB_{r3,k,h}^{c,t} = 0$ Steam turbine resource: $RT\_OLOC\_RC_{k,h}^{s,t} = Min\left[0, Max\left(-1 \times (RT\_ELOC_{k,h}^{s,t} + RT\_OLOC_{k,h}^{s,t}), \sum_{R} OLOC\_CB_{r,k,h}^{s,t}\right)\right]$							

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			Where: a. For synchronized *ten-minute operating reserve*: i. if $TAOR\_ST^{s,t}_{k,h} < RT\_OR\_LOC\_EOP^{s,t}_{r1,k,h}$ and if $RT\_QSOR^{s,t}_{r1,k,h} < RT\_OR\_LOC\_EOP^{s,t}_{r1,k,h}$ then: $$OLOC\_CB^{s,t}_{r1,k,h} = (-1) \times \left\{ OP\left(RT\_PROR^{s,t}_{r1,h}, RT\_OR\_LOC\_EOP^{s,t}_{r1,k,h}, RT\_OR\_DIPC^{s,t}_{r1,k,h} \right) - OP\left[RT\_PROR^{s,t}_{r1,h}, Max\left(RT\_QSOR^{s,t}_{r1,k,h}, TAOR\_ST^{s,t}_{k,h} \right), RT\_OR\_DIPC^{s,t}_{r1,k,h} \right] \right\}/12$$ ii. otherwise, $OLOC\_CB^{s,t}_{r1,k,h} = 0$ b. For non-synchronized *ten-minute operating reserve*: i. if $TAOR\_ST^{s,t}_{k,h} - RT\_QSOR^{s,t}_{r1,k,h} < RT\_OR\_LOC\_EOP^{s,t}_{r2,k,h}$ and if $RT\_QSOR^{s,t}_{r2,k,h} < RT\_OR\_LOC\_EOP^{s,t}_{r2,k,h}$, then: $$OLOC\_CB^{s,t}_{r2,k,h} = (-1) \times \left\{ OP\left(RT\_PROR^{s,t}_{r2,h}, RT\_OR\_LOC\_EOP^{s,t}_{r2,k,h}, RT\_OR\_DIPC^{s,t}_{r2,k,h} \right) - OP\left[RT\_PROR^{s,t}_{r2,h}, Max\left(RT\_QSOR^{s,t}_{r2,k,h}, TAOR\_ST^{s,t}_{k,h} - RT\_QSOR^{s,t}_{r1,k,h} \right), RT\_OR\_DIPC^{s,t}_{r2,k,h} \right] \right\}/12$$ ii. otherwise, $OLOC\_CB^{s,t}_{r2,k,h} = 0$ c. For *thirty-minute operating reserve*: i. if $TAOR\_ST^{s,t}_{k,h} - RT\_QSOR^{s,t}_{r1,k,h} - RT\_QSOR^{s,t}_{r2,k,h} < RT\_OR\_LOC\_EOP^{s,t}_{r3,k,h}$ and if $RT\_QSOR^{s,t}_{r3,k,h} < RT\_OR\_LOC\_EOP^{s,t}_{r3,k,h}$, then: $$OLOC\_CB^{s,t}_{r3,k,h} = (-1) \times \left\{ OP\left(RT\_PROR^{s,t}_{r3,h}, RT\_OR\_LOC\_EOP^{s,t}_{r3,k,h}, RT\_OR\_DIPC^{s,t}_{r3,k,h} \right) - OP\left[RT\_PROR^{s,t}_{r3,h}, Max\left(RT\_QSOR^{s,t}_{r3,k,h}, TAOR\_ST^{s,t}_{k,h} - RT\_QSOR^{s,t}_{r1,k,h} - RT\_QSOR^{s,t}_{r2,k,h} \right), RT\_OR\_DIPC^{s,t}_{r3,k,h} \right] \right\}/12$$ ii. otherwise, $OLOC\_CB^{s,t}_{r3,k,h} = 0$							

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
1910 MRP new	Real-Time Generator Offer Guarantee – Energy (RT_GOG – RT_GOG_COMP1) Component 1	MR Ch.9 ss.4.5.6, 4.5.15, and 4.5.22	GOG-eligible Resources that are not Pseudo-Units $$RT\_GOG\_COMP1_k^m = \sum^{T1}\left[(-1)\right.$$ $$\times Max\left(OP(RT\_LMP_h^{m,t}, RT\_QSI_{k,h}^{m,t}, BE_{k,h}^{m,t}), OP(RT\_LMP_h^{m,t}, AQEI_{k,h}^{m,t}, BE_{k,h}^{m,t})\right)$$ $$\left.+\frac{PD\_BE\_SNL_{k,h}^m}{12}\right] - \sum^{T0}\left[RT\_LMP_h^{m,t} \times AQEI_{k,h}^{m,t}\right]$$ $$+\sum^{RH}\left[DAM\_LMP_h^m \times DAM\_QSI_{k,h}^m/12\right]$$ Where: T1 = the set of contiguous metering intervals 't' within the real-time commitment period or the real-time reliability commitment period, as the case may be; T0 = the set of all metering intervals between the time when the resource is synchronized and injecting energy into the IESO-controlled grid and the time when the resource achieves its minimum loading point; RH = the set of contiguous settlement hours 'h' with day-ahead schedules for the ramp-up period in the day-ahead market that do not overlap with a pre-dispatch operational commitment; and if the combustion turbine resource or steam turbine resource is registered as a pseudo-unit but is not operating as a pseudo-unit and has a minimum constraint applied for combined cycle operation consistent with combustion turbine commitment, then $RT\_QSI_{k,h}^{m,t}$ will be replaced with $RT\_LC\_EOP_{k,h}^{m,t}$ for those metering intervals in which they have such constraint. GOG-eligible Resources that are Pseudo-Units: Combustion Turbine $$RT\_GOG\_COMP1_k^c =$$ $$\sum^{T1}\left[(-1) \times Max\left(OP(RT\_LMP_h^{c,t}, RT\_QSI_{k,h}^{c,t}, RT\_DIPC_{k,h}^{c,t}), OP(RT\_LMP_h^{c,t}, AQEI_{k,h}^{c,t}, RT\_DIPC_{k,h}^{c,t})\right)\right.$$ $$\left.+\frac{PD\_BE\_SNL_{k,h}^p}{12} \times (1 - ST\_Portion_{k,d1}^p)\right]$$ $$-\sum^{T0}\left(RT\_LMP_h^{c,t} \times AQEI_{k,h}^{c,t}\right) + \sum^{RH}\left[DAM\_LMP_h^c \times DAM\_QSI_{k,h}^c/12\right]$$	Interval	Either Way	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			Where: T1 = the set of contiguous metering intervals 't' within the real-time commitment period or the real-time reliability commitment period, as the case may be, for the combustion turbine resource;							

Where:

T1 = the set of contiguous metering intervals 't' within the real-time commitment period or the real-time reliability commitment period, as the case may be, for the combustion turbine resource;

p = the pseudo-unit associated with combustion turbine resource delivery point 'c';

T0 = the set of all metering intervals 't' between the time when the combustion turbine resource is synchronized and injecting energy into the IESO-controlled grid and the time when the combustion turbine resource achieves its minimum loading point; and

RH = the set of contiguous settlement hours 'h' with day-ahead schedules for the ramp-up period in the day-ahead market that do not overlap with a pre-dispatch operational commitment.

GOG-eligible Resources that are Pseudo-Units: Steam Turbine

$$RT\_GOG\_COMP1_k^s = \sum^{T1} \left[(-1) \times OP\left(RT\_LMP_h^{s,t}, RT\_CMT\_DIGQ_{k,h}^{s,t}, RT\_CMT\_DIPC_{k,h}^{s,t}\right) \right.$$
$$+ \sum_{p=1}^{N} \left(\frac{PD\_BE\_SNL_{k,h}^p}{12} \times ST\_Portion_{k,d1}^p \right)$$
$$\left. + \sum_{p=1}^{D} \left(DAM\_LMP_h^s \times \frac{\left[DAM\_QSI_{k,h}^p \times \left(ST\_Portion_{k,d1}^p\right)\right]}{12} \right) \right]$$
$$- \sum^{T0} \left(RT\_LMP_h^{s,t} \times AQEI_{k,h}^{s,t} \right)$$

Where:

T1 = the set of all metering intervals 't' in the steam turbine resource's real-time commitment period where at least one of the associated pseudo-units' real-time schedule is greater than or equal to its minimum loading point in accordance with a pre-dispatch operational commitment;

N = the set of all pseudo-units 'p' associated with steam turbine resource delivery point 's' that are eligible for a real-time generator offer guarantee settlement amount in metering interval 't' of settlement hour 'h';

D = the set of all pseudo-units 'p' associated with steam turbine resource delivery point 's' that have: (i) a pre-dispatch operational commitment greater than its minimum loading point in metering interval 't'; (ii) an associated combustion turbine resource that is injecting energy into the IESO-controlled grid in an amount greater than or equal to its minimum loading point in metering interval 't'; and (iii) a day-ahead schedule less than its minimum loading point in metering interval 't'; and

T0 = the set of all metering intervals 't' in the steam turbine resource's real-time commitment period when: (i) the steam turbine resource is injecting energy into the IESO-controlled grid in an amount that is

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			less than its 1-on-1 minimum loading point; and (ii) none of the associated pseudo-units have a day-ahead schedule.							
1911 MRP new	Real-Time Generator Offer Guarantee – Operating Reserve (RT_GOG – RT_GOG_COMP 2) Component 2	MR Ch.9 ss. 4.5.7, 4.5.16, and 4.5.23	GOG-eligible Resources that are not Pseudo-Units $$RT\_GOG\_COMP2_k^m = (-1) \times \sum_{R}^{T1} OP(RT\_PROR_{r,h}^{m,t}, RT\_QSOR_{r,k,h}^{m,t}, BOR_{r,k,h}^{m,t})$$ Where: T1 = the set of contiguous metering intervals 't' within the real-time commitment period or the real-time reliability commitment period, as the case may be. GOG-eligible Resources that are Pseudo-Units: Combustion Turbine $$RT\_GOG\_COMP2_k^c = \sum_{R}^{T1} \left[(-1) \times OP(RT\_PROR_{r,h}^{c,t}, RT\_QSOR_{r,k,h}^{c,t}, RT\_OR\_DIPC_{r,k,h}^{c,t})\right]$$ Where: T1 = the set of contiguous metering intervals 't' within the real-time commitment period or the real-time reliability commitment period, as the case may be, for the combustion turbine resource. GOG-eligible Resources that are Pseudo-Units: Steam Turbine $$RT\_GOG\_COMP2_k^s = \sum_{R}^{T1} \left[(-1) \times OP(RT\_PROR_{r,h}^{s,t}, RT\_OR\_CMT\_DIGQ_{r,k,h}^{s,t}, RT\_OR\_CMT\_DIPC_{r,k,h}^{s,t})\right]$$ Where: T1 = the set of all metering intervals 't' in the steam turbine resource's real-time commitment period where at least one of the associated pseudo-units is greater than or equal to its minimum loading point in accordance with a pre-dispatch operational commitment.	Interval	Either Way	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
1912 MRP new	Real-Time Generator Offer Guarantee – Over Midnight (RT_GOG – RT_GOG_COMP 3) Component 3	MR Ch.9 ss.4.5.8, 4.5.17, and 4.5.24	NOTE: this charge type has -1 added before the summation sign as it has been separated from the larger RT_GOG equation within the market rules, in which this component would have been subtracted from the total settlement amount. GOG-eligible Resources that are not Pseudo-Units $RT\_GOG\_COMP3_k^m = -1 \times \sum^{T2} [(-1) \, x \, (OP(RT\_LMP_h^{m,t}, MLP_k^m, BE_{k,h}^{m,t})) + \frac{PD\_BE\_SNL_{k,h}^m}{12}]$ Where: T2 = the set of contiguous metering intervals 't' beginning with the first metering interval of Day 1 and ending with the metering interval in Day 1 in which the resource completes its minimum generation block run-time that began in Day 0; and MLP_k^m = the minimum loading point of the resource for Day 1 for market participant 'k' for delivery point 'm'. GOG-eligible Resources that are Pseudo-Units: Combustion Turbine $RT\_GOG\_COMP3_k^c = -1$ $\times \sum^{T2} \left[(-1) \times \left(OP(RT\_LMP_h^{c,t}, MLP_k^c, RT\_DIPC_{k,h}^{c,t}) \right) + \frac{PD\_BE\_SNL_{k,h}^p}{12} \times (1$ $- ST\_Portion_{k,d1}^p) \right]$ Where: T2 = the set of contiguous metering intervals 't' beginning with the first metering interval of Day 1 and ending with the metering interval in Day 1 in which the resource completes its minimum generation block run-time that began in Day 0; MLP_k^c = the minimum loading point of the combustion turbine resource associated with combustion turbine resource delivery point 'c'; and p = the pseudo-unit associated with combustion turbine resource delivery point 'c'.	Interval	Either Way	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			GOG-eligible Resources that are Pseudo-Units: Steam Turbine $$RT\_GOG\_COMP3_k^s = -1$$ $$\times \sum^{U} \sum^{T_p} \left[(-1) \times \left(OP\left(RT\_LMP_h^{s,t}, (MLP_k^p \times ST\_Portion_{k,d1}^p), BE_{k,h}^{p,t}\right)\right) + \frac{PD\_BE\_SNL_{k,h}^p}{12} \times ST\_Portion_{k,d1}^p \right]$$ Where: U = the set of all pseudo-units 'p' associated with steam turbine resource delivery point 's' that have a real-time schedule in the first settlement hour of Day 1 to complete its minimum generation block run-time as part of a pre-dispatch operational commitment that began in Day 0 and forms part of the steam turbine resource's real-time commitment period; Tp = the set of metering intervals 't' where: (i) the associated pseudo-unit had a real-time schedule in the first settlement hour of Day 1 to complete its minimum generation block run-time; and (ii) the combustion turbine resource associated with pseudo-unit 'p' actually injected energy into the IESO-controlled grid in an amount equal to or greater than its minimum loading point; and MLP_k^p= the minimum loading point of pseudo-unit 'p' for market participant 'k' for Day 1.							
1913 MRP new	Real-Time Generator Offer Guarantee – Start-up (RT_GOG – RT_GOG_COMP 4) Component 4	MR Ch. ss.4.5.9, 4.5.18, and 4.5.25	GOG-eligible Resources that are not Pseudo-Units achieves minimum loading point within the first six metering intervals of the start of its minimum generation block run-time: $$RT\_GOG\_COMP4_{k,h}^m = RT\_GOG\_SU_{k,h}^m$$ achieves minimum loading point after the first six metering intervals of the start of its minimum generation block run-time but before the 19th metering interval following the start of its minimum generation block run-time: $$RT\_GOG\_COMP4_{k,h}^m = RT\_GOG\_SU_{k,h}^m - (RT\_GOG\_SU_{k,h}^m \times N\_INT / 12)$$	Interval	Due MP	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			Where N_INT = the number of metering intervals after the first six metering intervals that the resource took to achieve its minimum loading point. otherwise: $RT\_GOG\_COMP4_{k,h}^m = 0$ In determining $RT\_GOG\_SU_{k,h}^m$, if the resource: has either (a) a stand-alone pre-dispatch operational commitment; or (b) an advanced pre-dispatch operational commitment, that extends for longer than or equal to the resource's minimum generation block run-time plus its minimum generation block down-time for the hot thermal state, then: $RT\_GOG\_SU_{k,h}^m = PD\_BE\_SU_{k,h}^m$ receives an advanced pre-dispatch operational commitment that extends for a period that is less than the resource's minimum generation block run-time plus its minimum generation block down-time for the hot thermal state, then: $RT\_GOG\_SU_{k,h}^m = Max\left(0, PD\_BE\_SU_{k,h}^m - DAM\_BE\_SU_{k,h}^m\right)$ otherwise, $RT\_GOG\_SU_{k,h}^m = 0$ GOG-eligible Resources that are Pseudo-Units: Combustion Turbine For a pre-dispatch operational commitment where the associated pseudo-unit has a stand-alone pre-dispatch operational commitment or where the associated pseudo-unit receives a pre-dispatch operational commitment in advance of an existing day-ahead market operational commitment by a period that is greater than or equal to the resource's minimum generation block run-time plus its minimum generation block down-time for the hot thermal state: if the combustion turbine resource achieved its minimum loading point within the first six metering intervals of the start of the pre-dispatch operational commitment: $RT\_GOG\_COMP4_k^c = PD\_BE\_SU_{k,h}^p \times \left(1 - ST\_Portion_{k,d1}^p\right)$							

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			if the combustion turbine resource achieved its minimum loading point after the first six metering intervals of the start of its pre-dispatch operational commitment but before the 19th metering interval following the start of its pre-dispatch operational commitment: $$RT\_GOG\_COMP4_k^c = PD\_BE\_SU_{k,h}^p \times \left(1 - ST\_Portion_{k,d1}^p\right) \times \left(1 - \frac{N\_INT_k^c}{12}\right)$$ Where: $N\_INT_k^c$ = the number of metering intervals after the first six metering intervals that the combustion turbine resource took to achieve its minimum loading point. otherwise, $RT\_GOG\_COMP4_k^c = 0$ For a pre-dispatch operational commitment where the associated pseudo-unit has a pre-dispatch operational commitment in advance of an existing day-ahead market operational commitment by a period that is less than the resource's minimum generation block run-time plus its minimum generation block down-time for the hot thermal state: if the combustion turbine resource achieved its minimum loading point within the first six metering intervals of the start of the pre-dispatch operational commitment: $$RT\_GOG\_COMP4_k^c = Max\left(0, PD\_BE\_SU_{k,h}^p - DAM\_BE\_SU_{k,h}^p\right) \times \left(1 - ST\_Portion_{k,d1}^p\right)$$ if the combustion turbine resource achieved its minimum loading point after the first six metering intervals of the start of its pre-dispatch operational commitment but before the 19th metering interval following the start of its pre-dispatch operational commitment: $$RT\_GOG\_COMP4_k^c = Max\left(0, PD\_BE\_SU_{k,h}^p - DAM\_BE\_SU_{k,h}^p\right) \times \left(1 - ST\_Portion_{k,d1}^p\right) \times \left(1 - \frac{N\_INT_k^c}{12}\right)$$ Where: $N\_INT_k^c$ = the number of metering intervals after the first six metering intervals that the combustion turbine resource took to achieve its minimum loading point. otherwise, $RT\_GOG\_COMP4_k^c = 0$							

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			GOG-eligible Resources that are Pseudo-Units: Steam Turbine $$RT\_GOG\_COMP4_k^s = \sum_{c=1}^{C} \sum^{X_c} \left[RT\_GOG\_COMP4_{k,x}^c \times \frac{ST\_Portion_{k,d1}^p}{(1 - ST\_Portion_{k,d1}^p)} \right]$$ Where: C = the set of all combustion turbine resource delivery points 'c' associated with steam turbine resource delivery point 's'; $RT\_GOG\_COMP4_{k,x}^c$ = determined in accordance with MR Ch.9 s.4.5.18 for combustion turbine resource delivery point "c' for market participant 'k' for day-ahead commitment period 'x'; and Xc = the set of all pre-dispatch operational commitments 'x' that are classified as variant 1 and were incurred by combustion turbine resource 'c' during the steam turbine resource's real-time commitment period.							
1914 MRP new	Real-Time Generator Offer Guarantee – RT Make-Whole Payment Offset (RT_GOG – RT_GOG_COMP 5) Component 5	MR Ch.9 ss.4.5.11, 4.5.20, and 4.5.26	NOTE: this charge type has -1 added before the summation sign as it has been separated from the larger RT_GOG equation within the market rules, in which this component would have been subtracted from the total settlement amount. GOG-eligible Resources that are not Pseudo-Units $$RT\_GOG\_COMP5_k^m = -1 \times \sum^{T1} RT\_MWP_{k,h}^m$$ Where: T1 = the set of contiguous metering intervals 't' within the real-time commitment period or the real-time reliability commitment period, as the case may be. GOG-eligible Resources that are Pseudo-Units: Combustion Turbine $$RT\_GOG\_COMP5_k^c = -1 \times \sum^{T1} RT\_MWP_{k,h}^c$$ Where: T1 = the set of contiguous metering intervals 't' within the real-time commitment period or the real-time reliability commitment period, as the case may be, for the combustion turbine resource.	Interval	Due IESO	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			GOG-eligible Resources that are Pseudo-Units: Steam Turbine $$RT\_GOG\_COMP5_k^s = -1 \times \sum_{}^{T1} RT\_MWP_{k,h}^s$$ Where: T1 = the set of all metering intervals 't' in the steam turbine resource's real-time commitment period where at least one of the associated pseudo-units is greater than or equal to its minimum loading point in accordance with a pre-dispatch operational commitment.							
1915 MRP new	Real-Time Generator Offer Guarantee – Operating Reserve Non-Accessibility Reversal (RT_GOG - RT_GOG_CB)	MRs Ch.9 ss.3.10.3, 3.10.4, 3.10.5, 3.10.26-3.10.34	## GOG-eligible Resources that are not Pseudo-Units $$RT\_GOG\_CB_k^m = Max\left\{(-1)x RT\_GOG_k^m, Min\left[0, \sum_R^{T1}\left[ORSCB\_REV_{r,k,h}^{m,t} + COMP2\_CB_{r,k,h}^{m,t} - ORIA\_AMT_{r,k,h}^{m,t}\right] - \sum_{}^{T1} RT\_MWP\_RC_{k,h}^{m,t}\right]\right\}$$ Where: T1 = the set of all metering intervals 't' beginning from the first metering interval that the generation unit is at minimum loading point within a real-time commitment period or a real-time reliability commitment period until the last metering interval that the generation unit is at minimum loading point within such real-time commitment period or a real-time reliability commitment period, as applicable; $RT\_MWP\_RC_{k,h}^{m,t}$ = the real-time make-whole payment reversal charge settlement amount determined in accordance with MR Ch.9 ss.3.10.17-3.10.19 for charge types 1908 and 1909; $RSCB\_REV_{r,k,h}^{m,t} = (-1) \times ORSCB_{r,k,h}^{m,t}$ $COMP2\_CB_{r,k,h}^{m,t}$ and $ORIA\_AMT_{r,k,h}^{m,t}$ are calculated as follows: For synchronized ten-minute operating reserve if $TAOR_{k,h}^{m,t} < RT\_QSOR_{r1,k,h}^{m,t}$, then	Interval	Due IESO	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments

			$$COMP2\_CB_{r1,k,h}^{m,t} = \{OP[RT\_PROR_{r1,h}^{m,t}, RT\_QSOR_{r1,k,h}^{m,t}, BOR_{r1,k,h}^{m,t}] - OP(RT\_PROR_{r1,h}^{m,t}, TAOR_{k,h}^{m,t}, BOR_{r1,k,h}^{m,t})\}$$ $$ORIA\_AMT_{r1,k,h}^{m,t} = [RT\_PROR_{r1,h}^{m,t} \times (RT\_QSOR_{r1,k,h}^{m,t} - TAOR_{k,h}^{m,t})]$$ otherwise, $COMP2\_CB_{r1,k,h}^{m,t} = 0$ and $ORIA\_AMT_{r1,k,h}^{m,t} = 0$
			
			For non-synchronized ten-minute operating reserve
			if $TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t} < RT\_QSOR_{r2,k,h}^{m,t}$, then
			
			$$COMP2\_CB_{r2,k,h}^{m,t} = \{OP[RT\_PROR_{r2,h}^{m,t}, RT\_QSOR_{r2,k,h}^{m,t}, BOR_{r2,k,h}^{m,t}] - OP(RT\_PROR_{r2,h}^{m,t}, TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t}, BOR_{r2,k,h}^{m,t})\}$$ $$ORIA\_AMT_{r2,k,h}^{m,t} = [RT\_PROR_{r2,h}^{m,t} \times (RT\_QSOR_{r2,k,h}^{m,t} - Max(0, TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t}))]$$ otherwise, $COMP2_{CB_{r2,k,h}}^{m,t} = 0$ and $ORIA\_AMT_{r2,k,h}^{m,t} = 0$
			
			For thirty-minute operating reserve
			if $TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t} - RT\_QSOR_{r2,k,h}^{m,t} < RT\_QSOR_{r3,k,h}^{m,t}$, then
			
			$$COMP2\_CB_{r3,k,h}^{m,t} = \{OP[RT\_PROR_{r3,h}^{m,t}, RT\_QSOR_{r3,k,h}^{m,t}, BOR_{r3,k,h}^{m,t}] - OP(RT\_PROR_{r3,h}^{m,t}, TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t} - RT\_QSOR_{r2,k,h}^{m,t}, BOR_{r3,k,h}^{m,t})$$							

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			$$ORIA\_AMT_{r3,k,h}^{m,t} = \Big[RT\_PROR_{r3,h}^{m,t}$$ $$\times \Big(RT\_QSOR_{r3,k,h}^{m,t} - Max\,(0, TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t}$$ $$- \; RT\_QSOR_{r2,k,h}^{m,t} \Big) \Big]$$ otherwise, $COMP2\_CB_{r3,k,h}^{m,t} = 0$ and $ORIA\_AMT_{r3,k,h}^{m,t} = 0$ GOG-eligible Resources that are Pseudo-Units Combustion turbine resource: $$RT\_GOG\_CB_k^c = Max\Big\{(-1)xRT\_GOG_k^c, Min[0, \sum_R^{T1}\big[ORSCB\_REV_{r,k,h}^{c,t} + COMP2\_CB_{r,k,h}^{c,t} - ORIA\_AMT_{r,k,h}^{c,t}\big]$$ $$- \sum^{T1} RT\_MWP\_RC_{k,h}^{c,t}]\Big\}$$ Where: T1 = the set of all metering intervals 't' beginning from the first metering interval that the combustion turbine resource is at minimum loading point within a real-time commitment period or a real-time reliability commitment period until the last metering interval that the combustion turbine resource is at minimum loading point within such real-time commitment period or a real-time reliability commitment period, as applicable; $RT\_MWP\_RC_{k,h}^{c,t}$ = the real-time make-whole payment reversal charge settlement amount determined in accordance with MR Ch.9 ss.3.10.20-3.10.22 for charge types 1908 and 1909; $ORSCB\_REV_{r,k,h}^{c,t} = (-1) \times ORSCB_{r,k,h}^{c,t}$						

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments

			$COMP2\_CB_{r,k,h}^{c,t}$ and $ORIA\_AMT_{r,k,h}^{c,t}$ are calculated as follows:
			
			 For synchronized ten-minute operating reserve
			 if $TAOR\_CT_{k,h}^{c,t} < RT\_QSOR_{r1,k,h}^{c,t}$, then
			
			 $COMP2\_CB_{r1,k,h}^{c,t} = OP\big(RT\_PROR_{r1,h}^{c,t}, RT\_QSOR_{r1,k,h}^{c,t}, RT\_OR\_DIPC_{r1,k,h}^{c,t}\big)$ $- OP\big(RT\_PROR_{r1,h}^{c,t}, TAOR\_CT_{k,h}^{c,t}, RT\_OR\_DIPC_{r1,k,h}^{c,t}\big)$
			
			 $ORIA\_AMT_{r1,k,h}^{c,t} = \big[RT\_PROR_{r1,h}^{c,t} \times \big(RT\_QSOR_{r1,k,h}^{c,t} - TAOR\_CT_{k,h}^{c,t}\big)\big]$
			
			 otherwise $COMP2\_CB_{r1,k,h}^{c,t} = 0$ and $ORIA\_AMT_{r1,k,h}^{c,t} = 0$
			
			 For non-synchronized ten-minute operating reserve
			 if $TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t} < RT\_QSOR_{r2,,h}^{c,t}$, then
			
			 $COMP2\_CB_{r2,k,h}^{c,t} = OP\big(RT\_PROR_{r2,h}^{c,t}, RT\_QSOR_{r2,k,h}^{c,t}, RT\_OR\_DIPC_{r2,k,h}^{c,t}\big)$ $- OP\big(RT\_PROR_{r2,h}^{c,t}, TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t}, RT\_OR\_DIPC_{r2,k,h}^{c,t}\big)$
			
			 $ORIA\_AMT_{r2,k,h}^{c,t} = \big[RT\_PROR_{r2,h}^{c,t} \times \big(RT\_QSOR_{r2,k,h}^{c,t} - Max(0, TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t})\big)\big]$
			
			 otherwise $COMP2\_CB_{r2,k,h}^{c,t} = 0$ and $ORIA\_AMT_{r2,k,h}^{c,t} = 0$
			
			 For thirty-minute operating reserve
			 if $TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t} - RT\_QSOR_{r2,k,h}^{c,t} < RT\_QSOR_{r3,k,h}^{c,t}$, then							

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			$COMP2\_CB_{r3,k,h}^{c,t} = OP\left(RT\_PROR_{r3,h}^{c,t}, RT\_QSOR_{r3,k,h}^{c,t}, RT\_OR\_DIPC_{r3,k,h}^{c,t}\right)$ $- OP\left(RT\_PROR_{r3,h}^{c,t}, TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t} - RT\_QSOR_{r2,k,h}^{c,t}, RT\_OR\_DIPC_{r3,k,h}^{c,t}\right)$ $ORIA\_AMT_{r3,k,h}^{c,t} = \big[RT\_PROR_{r3,h}^{c,t}$ $\times \left(RT\_QSOR_{r3,k,h}^{c,t} - Max\left(0, TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t}\right.\right.$ $\left.\left. - RT\_QSOR_{r2,k,h}^{c,t}\right)\right]$ otherwise $COMP2\_CB_{r3,k,h}^{c,t} = 0$ and $ORIA\_AMT_{r3,k,h}^{c,t} = 0$ Steam turbine resource: $RT\_GOG\_CB_k^s = Max\left\{(-1)xRT\_GOG_k^s, Min[0, \sum_R^{T1}\left[ORSCB\_REV_{r,k,h}^{s,t} + COMP2\_CB_{r,k,h}^{s,t} - ORIA\_AMT_{r,k,h}^{s,t}\right]\right.$ $\left. - \sum^{T1} RT\_MWP\_RC_{k,h}^{s,t}\right]\right\}$ Where: T1 = the set of all metering intervals 't' beginning from the first metering interval that the steam turbine resource is at minimum loading point within a real-time commitment period or a real-time reliability commitment period until the last metering interval that the steam turbine resource is at minimum loading point within such real-time commitment period or a real-time reliability commitment period, as applicable; $RT\_MWP\_RC_{k,h}^{s,t}$ = the real-time make-whole payment reversal charge settlement amount determined in accordance with MR Ch.9 ss.3.10.23-3.10.25 for charge types 1908 and 1909; $ORSCB\_REV_{k,h}^{s,t} = -1 \times ORSCB_{k,h}^{s,t} \times \dfrac{\sum_R RT\_OR\_CMT\_DIGQ_{r,k,h}^{s,t}}{\sum_R RT\_SOR_{,k,h}^{s,t}}$ $RT\_GOG\_TAR\_ST_{k,h}^{s,t} = TAOR\_ST_{k,h}^{s,t} \times \dfrac{\sum_R RT\_OR\_CMT\_DIGQ_{r,k,h}^{s,t}}{\sum_R RT\_QSOR_{r,k,h}^{s,t}}$ $COMP2\_CB_{r,k,h}^{s,t}$ and $ORIA\_AMT_{r,k,h}^{s,t}$ are calculated as follows:							

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			A. For synchronized *ten-minute operating reserve* i. if $RT\_GOG\_TAOR\_ST_{k,h}^{s,t} < RT\_OR\_CMT\_DIGQ_{r1,k,h}^{s,t}$, then $COMP2\_CB_{r1,k,h}^{s,t} = OP\left(RT\_PROR_{r1,h}^{s,t}, RT\_OR\_CMT\_DIGQ_{r1,k,h}^{s,t}, RT\_OR\_CMT\_DIPC_{r1,k,h}^{s,t}\right)$ $\qquad - OP\left(RT\_PROR_{r1,h}^{s,t}, RT\_GOG\_TAOR\_ST_{k,h}^{s,t}, RT\_OR\_CMT\_DIPC_{r1,k,h}^{s,t}\right)$ $ORIA\_AMT_{r1,k,h}^{s,t} = \left[RT\_PROR_{r1,h}^{s,t} \times \left(RT\_OR\_CMT\_DIGQ_{r1,k,h}^{s,t} - RT\_GOG\_TAOR\_ST_{k,h}^{s,t}\right)\right]$ ii. otherwise $COMP2\_CB_{r1,k,h}^{s,t} = 0$ and $ORIA\_AMT_{r1,k,h}^{s,t} = 0$ B. For non-synchronized *ten-minute operating reserve* i. if $RT\_GOG\_TAOR\_ST_{k,h}^{s,t} - RT\_OR\_CMT\_DIGQ_{r1,k,h}^{s,t} < RT\_OR\_CMT\_DIGQ_{r2,k,h}^{s,t}$, then $COMP2\_CB_{r2,k,h}^{s,t} = OP\left(RT\_PROR_{r2,h}^{s,t}, RT\_OR\_CMT\_DIGQ_{r2,k,h}^{s,t}, RT\_OR\_CMT\_DIPC_{r2,k,h}^{s,t}\right)$ $\qquad - OP\left(RT\_PROR_{r2,h}^{s,t}, RT\_GOG\_TAOR\_ST_{k,h}^{s,t}\right.$ $\qquad \left. - RT\_OR\_CMT\_DIGQ_{r1,k,h}^{s,t}, RT\_OR\_CMT\_DIPC_{r2,k,h}^{s,t}\right)$ $ORIA\_AMT_{r2,k,h}^{s,t} = \left[RT\_PROR_{r2,h}^{s,t}\right.$ $\qquad \times \left(RT\_OR\_CMT\_DIGQ_{r2,k,h}^{s,t} - Max(0, RT\_GOG\_TAOR\_ST_{k,h}^{s,t}\right.$ $\qquad \left.\left.\left. - RT\_OR\_CMT\_DIGQ_{r1,k,h}^{s,t}\right)\right)\right]$ ii. otherwise $COMP2\_CB_{r2,k,h}^{s,t} = 0$ and $ORIA\_AMT_{r2,k,h}^{s,t} = 0$							

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			C. For *thirty-minute operating reserve* i. if $RT\_GOG\_TAOR\_ST_{k,h}^{s,t} - RT\_OR\_CMT\_DIGQ_{r1,k,h}^{s,t} - RT\_OR\_CMT\_DIGQ_{r2,k,h}^{s,t} < RT\_OR\_CMT\_DIGQ_{r3,k,h}^{s,t}$, then $$COMP2\_CB_{r3,k,h}^{s,t} = OP(RT\_PROR_{r3,h}^{s,t}, RT\_OR\_CMT\_DIGQ_{r3,k,h}^{s,t}, RT\_OR\_CMT\_DIPC_{r3,k,h}^{s,t}) - OP(RT\_PROR_{r3,h}^{s,t}, RT\_GOG\_TAOR\_ST_{k,h}^{s,t} - RT\_OR\_CMT\_DIGQ_{r1,k,h}^{s,t} - RT\_OR\_CMT\_DIGQ_{r2,k,h}^{s,t}, RT\_OR\_CMT\_DIPC_{r3,k,h}^{s,t})$$ $$ORIA\_AMT_{r3,k,h}^{s,t} = \left[RT\_PROR_{r3,h}^{s,t} \times \left(RT\_OR\_CMT\_DIGQ_{r3,k,h}^{s,t} - Max\left(0, RT\_GOG\_TAOR\_ST_{k,h}^{s,t} - RT\_OR\_CMT\_DIGQ_{r1,k,h}^{s,t} - RT\_OR\_CMT\_DIGQ_{r2,k,h}^{s,t}\right)\right)\right]$$ ii. otherwise $COMP2\_CB_{r3,k,h}^{s,t} = 0$ and $ORIA\_AMT_{r3,k,h}^{s,t} = 0$						
1917 MRP new	Real-Time Ramp-Down Settlement Amount (RT_RDSA)	MR Ch.9 s.4.6	GOG-eligible Resources that are not Pseudo-Units receives a real-time schedule less than its minimum loading point during a period when the GOG-eligible resource has a day-ahead schedule: $$RT\_RDSA_k^m = Max\left(0, \sum^T \left[(-1) \times OP(DAM\_LMP_h^m, AQEI_{k,h}^{m,t}, BE_{k,h}^{m,t}) - Max\left(0, (-1) \times OP(DAM\_LMP_h^m, AQEI_{k,h}^{m,t}, DAM\_BE_{k,h}^m)\right)\right]\right)$$ receives a real-time schedule less than its minimum loading point during a period when the GOG-eligible resource does not have a day-ahead schedule: $$RT\_RDSA_k^m = Max\left(0, \sum^T \left[(-1) \times OP(RT\_LMP_h^{m,t}, AQEI_{k,h}^{m,t}, BE_{k,h}^{m,t})\right]\right)$$ Where:	Interval	Due MP	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			T = ramp-down period determined as the set of all metering intervals 't' beginning with the first metering interval that the GOG-eligible resource is scheduled in the real-time market less than its minimum loading point and ends with the first metering interval following the start of 'T' in which the real-time schedule is zero or in which there is no real-time schedule; and $BE_{k,h}^{m,t}$ = the matrix of 'n' price-quantity pairs offered by market participant 'k' to supply energy during the settlement hour 'h' determined in accordance with the applicable market manual, where price is adjusted by being multiplied by the ramp-down factor specified in the applicable market manual. GOG-eligible Resources that are Pseudo-Units: Combustion Turbine receives a real-time schedule less than its minimum loading point during a period when the GOG-eligible resource has a day-ahead schedule: $$RT\_RDSA_k^c = Max\left(0, \sum^{T}\left[(-1) \times OP\left(DAM\_LMP_h^c, AQEI_{k,h}^{c,t}, RT\_DIPC_{k,h}^{c,t}\right)\right.\right.$$ $$\left.\left. - Max\left(0, (-1) \times OP\left(DAM\_LMP_h^c, AQEI_{k,h}^{c,t}, DAM\_DIPC_{k,h}^c\right)\right)\right]\right)$$ receives a real-time schedule less than its minimum loading point during a period when the GOG-eligible resource does not have a day-ahead schedule: $$RT\_RDSA_k^c = Max\left(0, \sum^{T}\left[(-1) \times OP\left(RT\_LMP_h^{c,t}, AQEI_{k,h}^{c,t}, RT\_DIPC_{k,h}^{c,t}\right)\right]\right)$$ Where: T = ramp-down period determined as the set of all metering intervals 't' beginning with the first metering interval that the GOG-eligible resource is scheduled in the real-time market less than its minimum loading point and ends with the first metering interval following the start of 'T' in which the real-time schedule is zero or in which there is no real-time schedule; and $RT\_DIPC_{k,h}^{c,t}$ = the matrix of 'n' price-quantity pairs during the settlement hour 'h' determined in accordance with the applicable market manual, where price is adjusted by being multiplied by the ramp-down factor specified in the applicable market manual. GOG-eligible Resources that are Pseudo-Units: Steam Turbine receives a real-time schedule less than its 1-on-1 minimum loading point during a period when the GOG-eligible resource has a day-ahead schedule:						

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			$$RT\_RDSA_k^s = Max\left(0, \sum^{T}\left[(-1) \times OP\left(DAM\_LMP_h^s, AQEI_{k,h}^{s,t}, RT\_DIPC_{k,h}^{s,t}\right)\right.\right.$$ $$\left.\left. - Max\left(0, (-1) \times OP\left(DAM\_LMP_h^s, AQEI_{k,h}^{s,t}, DAM\_DIPC_{k,h}^s\right)\right)\right]\right)$$ receives a real-time schedule less than its 1-on-1 minimum loading point during a period when the GOG-eligible resource does not have a day-ahead schedule: $$RT\_RDSA_k^s = Max\left(0, \sum^{T}\left[(-1) \times OP\left(RT\_LMP_h^{s,t}, AQEI_{k,h}^{s,t}, RT\_DIPC_{k,h}^{s,t}\right)\right]\right)$$ Where: T = ramp-down period determined as the set of all metering intervals 't' beginning with the first metering interval that the GOG-eligible resource is scheduled in the real-time market less than its 1-on-1 minimum loading point and ends with the first metering interval following the start of 'T' in which the real-time schedule is zero or in which there is no real-time schedule; and $RT\_DIPC_{k,h}^{s,t}$ = the matrix of 'n' price-quantity pairs, during the settlement hour 'h' determined in accordance with the applicable market manual, where price is adjusted by being multiplied by the ramp-down factor specified in the applicable market manual.							
1920 MRP new	Generator Failure Charge – Market Price Component (GFC_MPC)	MR Ch.9 ss.4.10.5, 4.10.8, and 4.10.9	GOG-eligible Resources that are not Pseudo-Units if the market participant provides less than four hours of advance notice of a given generator failure or fails to provide such notice: $$GFC\_MPC_{k,h}^m = \sum^{T} Min\left[0, -1 \times \left(RT\_LMP_h^{m,t} - PD\_LMP_h^{m,pdm}\right)\right.$$ $$\left. \times Max\left(0, PD\_QSI_{k,h}^{m,pdm} - Max\left(AQEI_{k,h}^{m,t}, DAM\_QSI_{k,h}^m\right)\right)\right]/12$$ if the market participant provides four hours or greater advance notice of a given generator failure: $$GFC\_MPC_{k,h}^m = \sum^{T} Min\left[0, -1 \times \left(Min\left(RT\_LMP_h^{m,t}, PD\_LMP_h^{m,pd1}\right) - PD\_LMP_h^{m,pdm}\right)\right.$$ $$\left. \times Max\left(0, PD\_QSI_{k,h}^{m,pdm} - Max\left(AQEI_{k,h}^{m,t}, DAM\_QSI_{k,h}^m\right)\right)\right]/12$$ Where:	Interval	Due IESO	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments

			T = the set of all metering intervals within settlement hour 'h' during which a generator failure is determined, in accordance with the applicable market manual, to have occurred at delivery point 'm'.
			
			GOG-eligible Resources that are Pseudo-Units: Combustion Turbine
			if the market participant provides less than four hours of advance notice of a given generator failure or fails to provide such notice:
			$$GFC\_MPC_{k,h}^c = \sum^T Min\big[0, (-1) \times \big(RT\_LMP_h^{c,t} - PD\_LMP_h^{c,pdm}\big)$$ $$\times Max\big(PD\_QSI_{k,h}^{c,pdm} - Max\big(AQEI_{k,h}^{c,t}, DAM\_QSI_{k,h}^c\big), 0\big)\big]/12$$
			
			if the market participant provides four hours or greater advance notice of a given generator failure:
			$$GFC\_MPC_{k,h}^c = \sum^T Min\big[0, (-1) \times \big(Min\big(RT\_LMP_h^{c,t}, PD\_LMP_h^{c,pd1}\big) - PD\_LMP_h^{c,pdm}\big)$$ $$\times Max\big(PD\_QSI_{k,h}^{c,pdm} - Max\big(AQEI_{k,h}^{c,t}, DAM\_QSI_{k,h}^c\big), 0\big)\big]/12$$
			
			Where:
			T = the set of all metering intervals at within settlement hour 'h' during which a generator failure is determined, in accordance with the applicable market manual, to have occurred at combustion turbine resource delivery point 'c'.
			
			GOG-eligible Resources that are Pseudo-Units: Steam Turbine
			$$GFC\_MPC_{k,h}^s = \sum^T GFC\_MPC_{k,h}^{s,t}$$
			
			if the market participant provides less than four hours of advance notice of a given generator failure or fails to provide such notice:
			$$GFC\_MPC_{k,h}^{s,t} = (-1) \times Max\big(RT\_LMP_h^{s,t} - Min\{c \in CT_F | PD\_LMP_h^{s,pdm}\}, 0\big)$$ $$\times Max\left(\sum^{M_t}[RT\_STP\_QSI_{k,h}^{p,t}] + \sum^{N_t}[PD\_STP\_QSI_{k,h}^{p,pdm}] - AQEI_{k,h}^{s,t}, 0\right)/12$$							

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			if the market participant provides four hours or greater advance notice of a given generator failure: $$GFC\_MPC_{k,h}^{s,t} = (-1) \times Max\big(Min(RT\_LMP_h^{s,t}, PD\_LMP_h^{s,pd1}) - Min\{c \in CT_F \mid PD\_LMP_h^{s,pdm}\}, 0\big)$$ $$\times Max\left(\sum^{M_t}[RT\_STP\_QSI_{k,h}^{p,t}] + \sum^{N_t}[PD\_STP\_QSI_{k,h}^{p,pdm}] - AQEI_{k,h}^{s,t}, 0\right)/12$$ Where: T = the set of all metering intervals within settlement hour 'h' during which a generator failure is determined, in accordance with the applicable market manual, to have occurred at steam turbine resource delivery point 's'. CTF = the set of all combustion turbine resources associated with steam turbine resource delivery point 's' having a combustion turbine resource failure interval or are operating in single cycle mode during metering interval 't'; Mt = the set of all pseudo-units associated with the steam turbine resource delivery point 's' whose associated combustion turbine resource does not have a combustion turbine resource failure interval and are not operating in single cycle mode during metering interval 't'; and Nt = the set of all pseudo-units associated with the steam turbine resource delivery point 's' whose associated combustion turbine resource has a combustion turbine resource failure interval or are operating in single cycle mode during metering interval 't'.						
1921 MRP new	Generator Failure Charge – Guarantee Cost Component (GFC_GCC)	MR Ch.9 ss.4.10.6, 4.10.10, and 4.10.11	GOG-eligible Resources that are not Pseudo-Units $$GFC\_GCC_{k,f}^m = -1 \times Max\Bigg[0, PD\_SU\_Ratio_{k,f}^m \times SU\_INCR_{k,f}^m$$ $$+ \sum^{T1} \frac{PD\_BE\_SNL_{k,h}^{m,pdm}}{12} - \sum^{T1} OP(PD\_LMP_h^{m,pdm}, PD\_QSI_{k,h}^{m,pdm}, PD\_BE^{m,pdm})/12\Bigg]$$ $$\times M1$$ Where: T1 = the set of all contiguous metering intervals at delivery point 'm' of the relevant generator failure, determined in accordance with the applicable market manual; M1 = the prorating factor based on the quantity of energy that the resource failed to deliver and calculated as:	Hourly	Due IESO	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			$$M1 = \left[1 - \frac{\sum^{T1} Min\left(PD\_QSI_{k,h}^{m,pdm}, Max\left(AQEI_{k,h}^{m,t}, DAM\_QSI_{k,h}^{m}\right)\right)}{\left(\sum^{T1} PD\_QSI_{k,h}^{m,pdm}\right)}\right]$$ if the pre-dispatch operational commitment violated by the generator failure 'f': advances a day-ahead operational commitment; and the number of advancement hours of the advanced pre-dispatch operational commitment is less than its minimum generation block run-time plus its minimum generation block down-time, then $$SU\_INCR_{k,f}^{m} = Max\left(0, PD\_BE\_SU_{k,f}^{m,pdm} - DAM\_BE\_SU_{k,f}^{m}\right)$$ if the pre-dispatch operational commitment violated by the generator failure 'f': is an extended pre-dispatch operational commitment, then $SU\_INCR_{k,f}^{m} = 0$ otherwise, $SU\_INCR_{k,f}^{m} = PD\_BE\_SU_{k,f}^{m,pdm}$ $PD\_SU\_Ratio_{k,f}^{m}$ = prorating factor for market participant 'k' at delivery point 'm' for generator failure 'f', and calculated as: i. if the *pre-dispatch operational commitment* violated by the *generator failure* 'f' is an *extended pre-dispatch operational commitment*, then $PD\_SU\_RATIO_{k,f}^{m} = 0$ ii. otherwise, $PD\_SU\_Ratio_{k,f}^{m} = Min\left(1, \frac{MLP\_INJ_{k,f}^{m}}{PD\_MGBRT_{k,f}^{m}}\right)$ Where: $MLP\_INJ_{k,f}^{m}$ = the number of metering intervals where the GOG-eligible resource for market participant 'k' injects energy into the IESO-controlled grid at delivery point 'm' in an amount less than its minimum loading point during the minimum generation block run-time associated with the pre-dispatch operational commitment associated with generator failure 'f'; and $PD\_MGBRT_{k,f}^{m}$ = the number of metering intervals of the minimum generation block run-time associated with the pre-dispatch operational commitment associated with generator failure 'f' for market participant 'k' at delivery point 'm'. GOG-eligible Resources that are Pseudo-Units: Combustion Turbine							

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments

			$GFC\_GCC_{k,f}^{c} = (-1) \times Max\left[0, PD\_SU\_Ratio_{k,f}^{c} \times SU\_INCR_{k,f}^{p,pdm} \times (1 - ST\_Portion_{k,d1}^{p})\right.$ $\left. + \sum^{T1}\left(\frac{PD\_BE\_SNL_{k,h}^{p,pdm}}{12} \times (1 - ST\_Portion_{k,d1}^{p})\right.\right.$ $\left.\left. - \frac{OP\left(PD\_LMP_{h}^{c,pdm}, PD\_QSI_{k,h}^{c,pdm}, PD\_DIPC_{k,h}^{c,t}\right)}{12}\right)\right] \times M1$
			
			Where:
			T1 = the set of all contiguous metering intervals at combustion turbine resource delivery point 'c' of the relevant generator failure, determined in accordance with the applicable market manual;
			M1 = the prorating factor based on the quantity of energy that the resource failed to deliver and calculated as:
			$M1 = \left[1 - \frac{\sum^{T1} Min\left(PD\_QSI_{k,h}^{c,pdm}, Max\left(AQEI_{k,h}^{c,t}, DAM\_QSI_{k,h}^{c}\right)\right)}{\left(\sum^{T1} PD\_QSI_{k,h}^{c,pdm}\right)}\right]$
			
			if the pre-dispatch operational commitment violated by the failure 'f' bridges with a day-ahead operational commitment and the number of advancement hours of the advanced pre-dispatch operational commitment is less than its minimum generation block run-time plus its minimum generation block down-time:
			$SU\_INCR_{k,f}^{p,pdm} = Max\left(0, PD\_BE\_SU_{k,f}^{p,pdm} - DAM\_BE\_SU_{k,f}^{p}\right)$
			
			if the pre-dispatch operational commitment violated by the generator failure 'f':
			
			i. is an *extended pre-dispatch operational commitment*, then $SU\_INCR_{k,f}^{p,pdm} = 0$
			
			ii. otherwise, $SU\_INCR_{k,f}^{p,pdm} = PD\_BE\_SU_{k,f}^{p,pdm}$
			
			$PD\_SU\_Ratio_{k,f}^{c}$ = prorating factor for market participant 'k' at combustion turbine resource delivery point 'c' for generator failure 'f', and calculated as:							

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			i. if the *pre-dispatch operational commitment* violated by the *generator failure* 'f' is an *extended pre-dispatch operational commitment*, then $PD\_SU\_RATIO^c_{k,f} = 0$ ii. otherwise, $PD\_SU\_Ratio^c_{k,f} = \text{Min}\left(1, \frac{MLP\_INJ^c_{k,f}}{PD\_MGBRT^c_{k,f}}\right)$ Where: $MLP\_INJ^c_{k,f}$ = the number of metering intervals where the GOG-eligible resource for market participant 'k' injects energy into the IESO-controlled grid at combustion turbine resource delivery point 'c' in an amount less than its minimum loading point during the minimum generation block run-time associated with the pre-dispatch operational commitment associated with generator failure 'f'; and $PD\_MGBRT^c_{k,f}$ = for market participant 'k' at combustion turbine resource delivery point 'c', the number of metering intervals of the minimum generation block run-time associated with the pre-dispatch operational commitment associated with generator failure 'f'. GOG-eligible Resources that are Pseudo-Units: Steam Turbine $$GFC\_GCC^s_k = (-1) \times Max\left[0, \sum^F \left(PD\_SU\_Ratio^c_{k,f} \times SU\_INCR^{p,pdm}_{k,f} \times ST\_Portion^p_{k,d1}\right)\right.$$ $$+ \sum^{T1}\sum^{CT_f}\left(\frac{PD\_BE\_SNL^{p,pdm}_{k,h}}{12} \times ST\_Portion^p_{k,d1}\right)$$ $$\left. - \sum^{T1}\left(OP\left[Min\{c \in CT_F | PD\_LMP^{s,pdm}_h\}, PD\_DIGQ^{s,t}_{k,h}, PD\_DIPC^{s,t}_{k,h}\right]/12\right)\right] \times M1$$ Where: T1 = the set of all contiguous metering intervals at steam turbine resource delivery point 's' of the relevant generator failure, determined in accordance with the applicable market manual; M1 = the prorating factor based on the quantity of energy that the resource failed to deliver and calculated as:							

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments

			$M1$
			
			$= \left[1 - \dfrac{\sum^{T1} Min(\sum^{N_t}[PD\_STP\_QSI_{k,h}^{p,pdm}], Max(AQEI_{k,h}^{s,t} - \sum^{M_t}(RT\_STP\_QSI_{k,h}^{p,t}), \sum^{N_t} DAM\_STP\_QSI_{k,h}^{p}))}{\sum^{T1}\sum^{N_t}[PD\_STP\_QSI_{k,h}^{p,pdm}]} \right]$
			
			if the combustion turbine resource's pre-dispatch operational commitment violated by failure 'f' bridges with a day-ahead operational commitment and the number of pre-dispatch advancement hours is less than its minimum generation block run-time plus its minimum generation block down-time:
			
			$SU\_INCR_{k,f}^{p,pdm} = Max(0, PD\_BE\_SU_{k,f}^{p,pdm} - DAM\_BE\_SU_{k,f}^{p})$
			
			if the pre-dispatch operational commitment violated by the generator failure 'f':
			
			is an extended pre-dispatch operational commitment, then $SU\_INCR_{k,f}^{p,pdm} = 0$
			
			otherwise, $SU\_INCR_{k,f}^{p,pdm} = PD\_BE\_SU_{k,f}^{p,pdm}$
			
			$PD\_SU\_Ratio_{k,f}^{c}$ = prorating factor for market participant 'k' at combustion turbine resource delivery point 'c' for generator failure 'f', and calculated as:
			
			i. if the *pre-dispatch operational commitment* violated by the *generator failure* 'f' is an *extended pre-dispatch operational commitment*, then $PD\_SU\_RATIO_{k,f}^{c} = 0$
			
			ii. otherwise, $PD\_SU\_Ratio_{k,f}^{c} = Min\left(1, \dfrac{MLP\_INJ_{k,f}^{c}}{PD\_MGBRT_{k,f}^{c}}\right)$
			
			Where:
			CTf = the set of all combustion turbine resources associated with steam turbine delivery point 's' having a combustion turbine resource failure interval during metering interval 't';
			
			Mt = the set of all pseudo-units associated with steam turbine resource delivery point 's' whose associated combustion turbine resource does not have a combustion turbine resource failure interval and are not operating in single cycle mode during metering interval 't';
			
			Nt = the set of all pseudo-units associated with steam turbine resource delivery point 's' whose associated combustion turbine resource has a combustion turbine resource failure interval or are operating in single cycle mode during metering interval 't';							

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			F = the set of all combustion turbine resource or steam turbine resource failures 'f' occurring during the period 'T1'; $MLP\_INJ^c_{k,f}$ = the number of metering intervals where the GOG-eligible resource for market participant 'k' injects energy into the IESO-controlled grid at combustion turbine resource delivery point 'c' in an amount less than its minimum loading point during the minimum generation block run-time associated with the pre-dispatch operational commitment associated with generator failure 'f'; and $PD\_MGBRT^c_{k,f}$ = for market participant 'k' at combustion turbine resource delivery point 'c', the number of metering intervals of the minimum generation block run-time associated with the pre-dispatch operational commitment associated with generator failure 'f'.							
1927 MRP new	Real-Time Intertie Offer Guarantee (RT_IOG)	MR Ch.9 s.3.6	$$RT\_IOG^i_{k,h} = Max\left[Potential\_IOG^i_{k,h} - IOG\_Offset^i_{k,h}, 0\right]$$ Where: $IOG\_Offset^i_{k,h}$ = the real-time intertie offer guarantee settlement amount offset for market participant 'k' in settlement hour 'h' in respect of intertie metering point 'i', and calculated as: $$IOG\_Offset^i_{k,h} = OFFSET\_MW^i_{k,h} \times IOG\_RATE^i_{k,h}$$ **and where:** i. $\quad IOG\_RATE^i_{k,h} = \frac{Potential\_IOG^i_{k,h}}{(\sum^T SQEI^{i,t}_{k,h} - DAM\_QSI^i_{k,h})/12}$ ii. $\quad IOG\_RATE^i_{k,h}$ shall be zero if $DAM\_QSI^i_{k,h}$ is greater than or equal to $SQEI^i_{k,h}$; and iii. $\quad OFFSET\_MW^i_{k,h}$ = the offset quantity of an eligible *energy* import transaction scheduled in the *real-time market*, as determined in accordance with MR Ch.9 s.3.6.5. b. $\quad Potential\_IOG^i_{k,h} = (-1) \times Min\left[0, \sum^T OP\left(RT\_LMP^{i,t}_h, SQEI^{i,t}_{k,h}, BE^{i,t}_{k,h}\right) - \sum^T OP\left(RT\_LMP^{i,t}_h, Min\left[SQEI^{i,t}_{k,h}, DAM\_QSI^i_{k,h}\right], BE^{i,t}_{k,h}\right)\right]/12$	Hourly	Due MP	N/A	13	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
1928 MRP new	Real-Time Import Failure Charge (RT_IMFC)	MR Ch.9 ss.3.7.1-3.7.4	$RT\_IMFC_{k,h}^i = \sum^T \Big[(-1)$ $\times Min\Big(Max\big(0, (RT\_IBP_h^{i,t} + PB\_IM_h^t - PD\_IBP_h^i) \times RT\_ISD_{k,h}^{i,t}\big), Max\big(0, RT\_IBP_h^{i,t}$ $\times RT\_ISD_{k,h}^{i,t}\big)\Big) + Min\big(0, RT\_PEC_h^{i,t} + RT\_PNISL_{k,h}^{i,t}\big) \times RT\_ISD_{k,h}^{i,t}\Big]/12$ Where: a. $RT\_ISD_{k,h}^{i,t} = Max\big(PD\_QSI_{k,h}^i - Max(DAM\_QSI_{k,h}^i, SQEI_{k,h}^i), 0\big).$	Interval	Due IESO	N/A	13	N/A	N/A	
1929 MRP new	Real-Time Export Failure Charge (RT_EXFC)	MR Ch.9 ss.3.7.1-3.7.2, and 3.7.5 – 3.7.6	$RT\_EXFC_{k,h}^i = \sum^T \Big[(-1)$ $\times Min\Big(Max\big(0, (PD\_IBP_h^i - PB\_EX_h^t - RT\_IBP_h^{i,t}) \times RT\_ESD_{k,h}^{i,t}\big), Max\big(0, PD\_IBP_h^i$ $\times RT\_ESD_{k,h}^{i,t}\big)\Big) - Max\big(0, RT\_PEC_h^{i,t} + RT\_PNISL_{k,h}^{i,t}\big) \times RT\_ESD_{k,h}^{i,t}\Big]/12$ Where: a. $RT\_ESD_{k,h}^{i,t} = Max\big(PD\_QSW_{k,h}^i - Max(DAM\_QSW_{k,h}^i, SQEW_{k,h}^{i,t}), 0\big).$	Interval	Due IESO	N/A	N/A	0	13	
1930 MRP new	Day-Ahead Market Reference Level Settlement Charge (DAM_RLSC)	MR Ch.9 s.5.2	$DAM\_RLSC_{k,h}^m = -1 \times DAM\_QSI_{k,h}^m \times (DAM\_LMP_h^m - DAM\_PLCP_{k,h}^m)$ Where: $DAM\_PLCP_{k,h}^m$ = the price component Pn of N-by-2 matrix ($DAM\_RLL_{k,h}^m$) of price-quantity pairs where 'n' is the highest indexed row of the matrix such that $DAM\_QSI_{k,h}^m \le Q_n$.	Hourly	Due IESO	13	N/A	N/A	N/A	
1931 MRP new	Real-Time Reference Level Settlement Charge	MR Ch.9 s.5.3	$RT\_RLSC_{k,h}^m = -1 \times \sum^T (RT\_QSI_{k,h}^{m,t} \times (RT\_LMP_h^{m,t} - RT\_PLCP_{k,h}^m))$ Where:	Hourly	Due IESO	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
	(RT_RLSC)		$RT\_PLCP_{k,h}^{m}$ = the price component Pn of N-by-2 matrix $(RT\_RLL_{k,h}^{m})$ of price-quantity pairs where 'n' is the highest indexed row of the matrix such that $RT\_QSI_{k,h}^{m} \leq Q_n$.							
1932 MRP new	Mitigation Amount for Physical Withholding – Energy (EXP_PWSC – PW_E)	MR Ch.9 s.5.4.1.1	NOTE: this charge type has -1 added before the summation sign as it has been separated from the larger ex-post mitigation for physical withholding equation within the market rules, in which the total settlement amount is multiplied by -1 because it is an amount owing to the IESO. $$PW\_E_k^m = -1 \, x \sum_{}^{H} Max(DAM\_PW_{k,h}^m, RT\_PW_{k,h}^m) \times PM\_PW_{mcepw}$$ Where: H = the set of settlement hours 'h' of the trading day for which the IESO determined that the market participant engaged in physical withholding in the day-ahead market, the real-time market, or both; PM_PW_{mcepw} = the persistence multiplier applicable to the relevant trading day for the market control entity for physical withholding 'mcepw' that the registered market participant for the applicable resource designated, as determined with the applicable market manual; and c. $DAM\_PW_{k,h}^m = 1.5 \times \left(MWhs\ Failed_{k,h}^m\right) \times (DAM\_LMP_h^m)$ Where: h = the settlement hour in the relevant trading day for which the IESO determined that the market participant engaged in physical withholding in the day-ahead market; and $MWhs\ Failed_{k,h}^m$ = the quantity of energy (in MWhs) for market participant 'k' at delivery point 'm' for settlement hour 'h', as determined in accordance with the following: if the IESO is assessing physical withholding in only the real-time market, it is deemed to be zero; and otherwise, it is determined by subtracting the market participant's energy offer from the energy reference quantity value or alternative reference quantity value, as the case may be, of the resource associated with the offer. d. $RT\_PW_{k,h}^m = 1.5 \times \sum^T \left(MWhs\ Failed_{k,h}^{m,t}\right) \times \left(RT\_LMP_h^{m,t}\right)$ Where: T = the set of all metering intervals 't' in settlement hour 'h' for which the IESO determined that the market participant engaged in physical withholding in the real-time market; and	Daily	Due IESO	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			$MWhs\ Failed_{k,h}^{m,t}$ = the quantity of energy (in MWhs) for market participant 'k' at delivery point 'm' in metering interval 't' of settlement hour 'h', as determined in accordance with the following: if the IESO is assessing physical withholding in only the day-ahead market, it is deemed to be zero; and otherwise, it is determined by subtracting the market participant's energy offer from the energy offer reference quantity value or alternative reference quantity value, as the case may be, of the resource associated with the offer.							
1933 MRP new	Mitigation Amount for Physical Withholding – 10S Operating Reserve (EXP_PWSC – PW_OR)	MR Ch.9 s.5.4.1.2	NOTE: this charge type has -1 added before the summation sign as it has been separated from the larger ex-post mitigation for physical withholding equation within the market rules, in which the total settlement amount is multiplied by -1 because it is an amount owing to the IESO. $$PW\_OR_k^m = -1\ x \sum_{}^{H} Max(DAM\_PW_{k,h}^m, RT\_PW_{k,h}^m) \times PM\_PW_{mcepw}$$ Where: H = the set of settlement hours 'h' of the trading day for which the IESO determined that the market participant engaged in physical withholding in either the day-ahead market or the real-time market; PM_PW_{mcepw}= the persistence multiplier applicable to the relevant trading day for the market control entity for physical withholding 'mcepw' that the registered market participant for the applicable resource designated, as determined with the applicable market manual; c. $DAM\_PW_{k,h}^m = 1.5 \times (MWs\ Failed_{r1,k,h}^m \times DAM\_PROR_{r1,h}^m)$ Where: h = the settlement hour in the relevant trading day for which the IESO determined that the market participant engaged in physical withholding in the day-ahead market; and $MWs\ Failed_{r1,k,h}^m$ = the quantity of spinning ten-minute operating reserve (in MWs) for market participant 'k' at delivery point 'm' for settlement hour 'h', as determined in accordance with the following: if the IESO is assessing physical withholding in only the real-time market, it is deemed to be zero; and otherwise, it is determined by subtracting the market participant's operating reserve offer from the operating reserve reference quantity value or alternative reference quantity value, as the case may be, of the resource associated with the offer. d. $RT\_PW_{k,h}^m = 1.5 \times \sum^{T}(MWs\ Failed_{r1,k,h}^{m,t} \times RT\_PROR_{r1,h}^{m,t})$	Daily	Due IESO	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			Where: T = the set of all metering intervals 't' in settlement hour 'h' for which the IESO determined that the market participant engaged in physical withholding in the real-time market; and $MWs\ Failed_{r1,k,h}^{m,t}$ = the quantity of spinning ten-minute operating reserve (in MWs) for market participant 'k' at delivery point 'm' in metering interval 't' of settlement hour 'h', as determined in accordance with the following: if the IESO is assessing physical withholding in only the day-ahead market, it is deemed to be zero; and otherwise, it is determined by subtracting the market participant's operating reserve offer from the operating reserve reference quantity value or alternative reference quantity value, as the case may be, of the resource associated with the offer.							
1934 MRP new	Mitigation Amount for Physical Withholding – 10N Operating Reserve (EXP_PWSC – PW_OR)	MR Ch.9 s.5.4.1.2	NOTE: this charge type has -1 added before the summation sign as it has been separated from the larger ex-post mitigation for physical withholding equation within the market rules, in which the total settlement amount is multiplied by -1 because it is an amount owing to the IESO. $$PW\_OR_k^m = -1\ x \sum^{H} Max(DAM\_PW_{k,h}^m, RT\_PW_{k,h}^m) \times PM\_PW_{mcepw}$$ Where: H = the set of settlement hours 'h' of the trading day for which the IESO determined that the market participant engaged in physical withholding in either the day-ahead market or the real-time market; PM_PW_{mcepw}= the persistence multiplier applicable to the relevant trading day for the market control entity for physical withholding 'mcepw' that the registered market participant for the applicable resource designated, as determined with the applicable market manual; c. $DAM\_PW_{k,h}^m = 1.5 \times (MWs\ Failed_{r2,k,h}^m \times DAM\_PROR_{r2,h}^m)$ Where: h = the settlement hour in the relevant trading day for which the IESO determined that the market participant engaged in physical withholding in the day-ahead market; and $MWs\ Failed_{r2,k,h}^m$ = the quantity of non-spinning ten-minute operating reserve (in MWs) for market participant 'k' at delivery point 'm' for settlement hour 'h', as determined in accordance with the following: if the IESO is assessing physical withholding in only the real-time market, it is deemed to be zero; and	Daily	Due IESO	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			otherwise, it is determined by subtracting the market participant's operating reserve offer from the operating reserve reference quantity value or alternative reference quantity value, as the case may be, of the resource associated with the offer. d. $RT\_PW_{k,h}^{m} = 1.5 \times \sum^{T}(MWs\ Failed_{r2,k,h}^{m,t} \times RT\_PROR_{r2,h}^{m,t})$ Where: T = the set of all metering intervals 't' in settlement hour 'h' for which the IESO determined that the market participant engaged in physical withholding in the real-time market; and $MWs\ Failed_{r2,k,h}^{m,t}$ = the quantity of non-spinning ten-minute operating reserve (in MWs) for market participant 'k' at delivery point 'm' in metering interval 't' of settlement hour 'h', as determined in accordance with the following: if the IESO is assessing physical withholding in only the day-ahead market, it is deemed to be zero; and otherwise, it is determined by subtracting the market participant's operating reserve offer from the operating reserve reference quantity value or alternative reference quantity value, as the case may be, of the resource associated with the offer.						
1935 MRP new	Mitigation Amount for Physical Withholding – 30R Operating Reserve (EXP_PWSC – PW_OR)	MR Ch.9 s.5.4.1.2	NOTE: this charge type has -1 added before the summation sign as it has been separated from the larger ex-post mitigation for physical withholding equation within the market rules, in which the total settlement amount is multiplied by -1 because it is an amount owing to the IESO. $PW\_OR_{k}^{m} = -1\ x \sum^{H} Max(DAM\_PW_{k,h}^{m}, RT\_PW_{k,h}^{m}) \times PM\_PW_{mcepw}$ Where: H = the set of settlement hours 'h' of the trading day for which the IESO determined that the market participant engaged in physical withholding in either the day-ahead market or the real-time market; PM_PW_{mcepw} = the persistence multiplier applicable to the relevant trading day for the market control entity for physical withholding 'mcepw' that the registered market participant for the applicable resource designated, as determined with the applicable market manual;	Daily	Due IESO	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
			c. $\quad DAM\_PW_{k,h}^m = 1.5 \times (MWs\ Failed_{r3,k,h}^m \times DAM\_PROR_{r3,h}^m)$ Where: h = the settlement hour in the relevant trading day for which the IESO determined that the market participant engaged in physical withholding in the day-ahead market; and $MWs\ Failed_{r3,k,h}^m$ = the quantity of thirty-minute operating reserve (in MWs) for market participant 'k' at delivery point 'm' for settlement hour 'h', as determined in accordance with the following: if the IESO is assessing physical withholding in only the real-time market, it is deemed to be zero; and otherwise, it is determined by subtracting the market participant's operating reserve offer from the operating reserve reference quantity value or alternative reference quantity value, as the case may be, of the resource associated with the offer. d. $\quad RT\_PW_{k,h}^m = 1.5 \times \sum^T (MWs\ Failed_{r3,k,h}^{m,t} \times RT\_PROR_{r3,h}^{m,t})$ Where: T = the set of all metering intervals 't' in settlement hour 'h' for which the IESO determined that the market participant engaged in physical withholding in the real-time market; and $MWs\ Failed_{r3,k,h}^{m,t}$ = the quantity of thirty-minute operating reserve (in MWs) for market participant 'k' at delivery point 'm' in metering interval 't' of settlement hour 'h', as determined in accordance with the following: if the IESO is assessing physical withholding in only the day-ahead market, it is deemed to be zero; and otherwise, it is determined by subtracting the market participant's operating reserve offer from the operating reserve reference quantity value or alternative reference quantity value, as the case may be, of the resource associated with the offer.						
1936 MRP new	Mitigation Amount for Intertie Economic Withholding – Energy	MR Ch.9 s.5.5.1.1	NOTE: this charge type has -1 added before the summation sign as it has been separated from the larger ex-post mitigation for intertie economic withholding equation within the market rules, in which the total settlement amount is multiplied by -1 because it is an amount owing to the IESO. $EW\_E_k^i = -1 \ x \sum^H Max(DAM\_EWUI_{k,h}^i, RT\_EWUI_{k,h}^i)$	Daily	Due IESO	N/A	13	0	13	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
	(EXP_EWSC – EW_E)		Where: H = the set of settlement hours 'h' of the trading day for which the IESO determined that the market participant engaged in intertie economic withholding in the day-ahead market, real-time market, or both; b. $\quad DAM\_EWUI_{k,h}^{i} = \left(MWhs\ Failed_{k,h}^{i}\right) \times DAM\_LMP_{h}^{i}$ Where: h = the settlement hour for which the IESO determined that the market participant engaged in intertie economic withholding in the day-ahead market; and $MWhs\ Failed_{k,h}^{i}$ = the quantity of energy (in MWhs) for market participant 'k' at intertie metering point 'i' for settlement hour 'h', as determined in accordance with the following: if the IESO is assessing intertie economic withholding in only the real-time market, it is deemed to be zero; and otherwise, it is determined by subtracting the market participant's energy offer from the energy reference quantity value of the resource associated with the offer. c. $\quad RT\_EWUI_{k,h}^{i} = \sum^{T}\left(MWhs\ Failed_{k,h}^{i,t}\right) \times \left(RT\_LMP_{h}^{i,t}\right)$ Where: T = the set of all metering intervals 't' in settlement hour 'h' for which the IESO determined that the market participant engaged in intertie economic withholding in the real-time market; and $MWhs\ Failed_{k,h}^{i,t}$ = the quantity of energy (in MWhs) for market participant 'k' at intertie metering point 'i' for settlement hour 'h', as determined in accordance with the following: if the IESO is assessing intertie economic withholding in only the day-ahead market, it is deemed to be zero; and otherwise, it is determined by subtracting the market participant's energy offer from the energy reference quantity value of the resource associated with the offer.							
1937 MRP new	Mitigation Amount for Intertie Economic Withholding –	MR Ch.9 s.5.5.1.3	NOTE: this charge type has -1 added before the summation sign as it has been separated from the larger ex-post mitigation for intertie economic withholding equation within the market rules, in which the total settlement amount is multiplied by -1 because it is an amount owing to the IESO. $EW\_OR_{k}^{i} = -1x \sum^{H} Max\left(DAM\_EWUI_{k,h}^{i}, RT\_EWUI_{k,h}^{i}\right)$	Daily	Due IESO	N/A	13	0	13	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
	10N Operating Reserve (EXP_EWSC – EW_OR)		Where: H = the set of settlement hours 'h' of the trading day for which the IESO determined that the market participant engaged in intertie economic withholding in either the day-ahead market or the real-time market; b. $DAM\_EWUI_{k,h}^{i} = (MWs\ Failed_{r2,k,h}^{i} \times DAM\_PROR_{r2,h}^{i})$ Where: h = the settlement hour for which the IESO determined that the market participant engaged in intertie economic withholding in the day-ahead market; and $MWs\ Failed_{r2,k,h}^{i}$ = the quantity of non-spinning ten-minute operating reserve (in MWs) for market participant 'k' at intertie metering point 'i' for settlement hour 'h', as determined in accordance with the following: if the IESO is assessing intertie economic withholding in only the real-time market, it is deemed to be zero; and otherwise, it is determined by subtracting the market participant's operating reserve offer from the operating reserve reference quantity value of the resource associated with the offer. c. $RT\_EWUI_{k,h}^{i} = \sum^{T}(MWs\ Failed_{r2,k,h}^{i,t} \times RT\_PROR_{r2,h}^{i,t})$ Where: T = the set of all metering intervals 't' in settlement hour 'h' for which the IESO determined that the market participant engaged in intertie economic withholding in the real-time market; and $MWs\ Failed_{r2,k,h}^{i,t}$ = the quantity of non-spinning ten-minute operating reserve (in MWs) for market participant 'k' at intertie metering point 'i' for metering interval 't' in settlement hour 'h', as determined in accordance with the following: if the IESO is assessing intertie economic withholding in only the day-ahead market, it is deemed to be zero; and otherwise, it is determined by subtracting the market participant's operating reserve offer from the operating reserve reference quantity value of the resource associated with the offer.							
1938 MRP new	Mitigation Amount for Intertie Economic Withholding –	MR Ch.9 s.5.5.1.3	NOTE: this charge type has -1 added before the summation sign as it has been separated from the larger ex-post mitigation for intertie economic withholding equation within the market rules, in which the total settlement amount is multiplied by -1 because it is an amount owing to the IESO.	Daily	Due IESO	N/A	13	0	13	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
	30R Operating Reserve (EXP_EWSC – EW_OR)		$EW\_OR_k^i = -1 \: x \sum\limits^{H} Max(DAM\_EWUI_{k,h}^i, RT\_EWUI_{k,h}^i)$ Where: H = the set of settlement hours 'h' of the trading day for which the IESO determined that the market participant engaged in intertie economic withholding in either the day-ahead market or the real-time market; b. $DAM\_EWUI_{k,h}^i = (MWs\:Failed_{r3,k,h}^i \times DAM\_PROR_{r3,h}^i)$ Where: h = the settlement hour for which the IESO determined that the market participant engaged in intertie economic withholding in the day-ahead market; and $MWs\:Failed_{r3,k,h}^i$ = the quantity of thirty-minute operating reserve (in MWs) for market participant 'k' at intertie metering point 'i' for settlement hour 'h', as determined in accordance with the following: if the IESO is assessing intertie economic withholding in only the real-time market, it is deemed to be zero; and otherwise, it is determined by subtracting the market participant's operating reserve offer from the operating reserve reference quantity value of the resource associated with the offer. c. $RT\_EWUI_{k,h}^i = \sum^T(MWs\:Failed_{r3,k,h}^{i,t} \times RT\_PROR_{r3,h}^{i,t})$ Where: T = the set of all metering intervals 't' in settlement hour 'h' for which the IESO determined that the market participant engaged in intertie economic withholding in the real-time market; and $MWs\:Failed_{r3,k,h}^{i,t}$ = the quantity of thirty-minute operating reserve (in MWs) for market participant 'k' at intertie metering point 'i' for metering interval 't' in settlement hour 'h', as determined in accordance with the following: if the IESO is assessing intertie economic withholding in only the day-ahead market, it is deemed to be zero; and otherwise, it is determined by subtracting the market participant's operating reserve offer from the operating reserve reference quantity value of the resource associated with the offer.							

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
1939 MRP new	Mitigation Amount for Intertie Economic Withholding – Make-Whole Payment (EXP_EWSC – EW_MWP)	MR Ch.9 s.5.5.1.2	NOTE: this charge type has -1 added before the summation sign as it has been separated from the larger ex-post mitigation for intertie economic withholding equation within the market rules, in which the total settlement amount is multiplied by -1 because it is an amount owing to the IESO. $$EW\_MWP_k^i = -1 \times \sum^{H} \left(DAM\_MWP_{k,h}^i - IRL\_DAM\_MWP_{k,h}^i\right) + \left(RT\_MWP_{k,h}^i - IRL\_RT\_MWP_{k,h}^i\right) + \left(RT\_IOG_{k,h}^i - IRL\_RT\_IOG_{k,h}^i\right)$$ Where: H = the set of settlement hours 'h' of the trading day for which the IESO determined that the market participant engaged in intertie economic withholding in the day-ahead market, the real-time market, or both; $IRL\_DAM\_MWP_{k,h}^i$ = the day-ahead market make-whole payment amount calculated in accordance with MR Ch.9 s.3.4 utilizing the resource's intertie reference level value that was used by the IESO to assess intertie economic withholding in accordance with MR Ch.7 s.22.18; $IRL\_RT\_MWP_{k,h}^i$ = the real-time make-whole payment amount calculated in accordance with 9.3.5 utilizing the resources intertie reference level value that was used by the IESO to assess intertie economic withholding in accordance with MR Ch.7 s.22.18; and $IRL\_RT\_IOG_{k,h}^i$ = the real-time intertie offer guarantee amount calculated in accordance with MR Ch.9 s.3.6 utilizing the resource's intertie reference level value that was used by the IESO to assess intertie economic withholding in accordance with MR Ch.7 s.22.18.	Daily	Due IESO	N/A	13	0	13	
1940 MRP new	Reference Level and Reference Quantity Independent Review Process Settlement Amount	MR Ch.7 s.22.8.14	Manual entry as per MR Ch.7 s.22.8.14.	Monthly	Due IESO	13	N/A	N/A	N/A	
1941 MRP new	Reference Level and Reference Quantity Independent Review Process Recovery	MR Ch.9 s.4.14.12	Manual entry as per MR Ch.7 s.22.8.11.2.	Monthly	Due IESO	13	N/A	0	13	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
	Amount (Market)									
1950 MRP new	Real-Time Make-Whole Payment Uplift (RT_MWPU)	MR Ch.9 s.3.11	$$= \sum_{C}^{M,T} TD_{k,h,c} \; x \left[\sum^{M,T} \left(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t} + RQ_{k,h}^{m,i,t}\right) / \sum_{K}^{M,T} \left(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}\right)\right]$$ Where: C = the set of all charge types 'c' as follows: 1900,1901,1902,1903,1904,1905,1906,1907,1908,1909.	Hourly	Due IESO	13	N/A	0	13	
1960 MRP new	Real-Time Generator Offer Guarantee Uplift (RT_GOGU)	MR Ch.9 s.4.14.2	$$RT\_GOGU_k = -1 \; x \sum_{K,H}^{M,T} \left(RT\_GOG_{k,h}^m + RT\_GOG\_CB_{k,h}^m\right)$$ $$\times \left[\sum_{H}^{M,T} \left(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}\right) / \sum_{K,H}^{M,T} \left(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}\right)\right]$$ Where: $RT\_GOG_{k,h}^m$ = the real-time generator offer guarantee settlement amount calculated for charge types 1910,1911,1912,1913, and 1914 in accordance with MR Ch.9 s.4.5 for market participant 'k' at delivery point 'm' for settlement hour 'h'; and $RT\_GOG\_CB_{k,h}^m$ = the real-time generator offer guarantee clawback settlement amount calculated for charge type 1915 in accordance with MR Ch.9 ss.3.10.26-3.10.34 for market participant 'k' at delivery point 'm' for settlement hour 'h'.	Daily	Due IESO	13	N/A	0	13	
1967 MRP new	Real-Time Ramp-Down Settlement Amount Uplift (RT_RDSAU)	MR Ch.9 s.4.14.11	$$RT\_RDSAU_k = -1 \; x \sum_{K}^{M,T} RT\_RDSA_k^m \times \left[\sum^{M,T} \left(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}\right) / \sum_{K}^{M,T} \left(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}\right)\right]$$ Where: $RT\_RDSA_k^m$ = the real-time ramp-down settlement amount calculated for charge type 1927 in accordance with MR Ch.9 s.4.6 for market participant 'k' at delivery point 'm'.	Daily	Due IESO	13	N/A	0	13	
1970 MRP new	Generator Failure Charge – Market Price	MR Ch.9 s.3.11	$$= \sum_{C}^{M,T} TD_{k,h,c} \; x \left[\sum^{M,T} \left(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t} + RQ_{k,h}^{m,i,t}\right) / \sum_{K}^{M,T} \left(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}\right)\right]$$	Hourly	Due MP	13	N/A	0	13	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
	Component Uplift (GFC_MPCU)		Where: C = the set of all charge types 'c' as follows: 1920.							
1971 MRP new	Generator Failure Charge – Guarantee Cost Component Uplift (GFC_GCCU)	MR Ch.9 s.4.14.1	$$GFC\_GCCU_k = -1\,x \sum_{K,F}^{M} GFC\_GCC_{k,f}^{m} \times \left[\sum_{H}^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}) / \sum_{K,H}^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}) \right]$$ Where: $GFC\_GCC_{k,f}^{m}$ = the generator failure charge – guarantee cost component calculated for charge type 1921 in accordance with MR Ch.9 s.4.10 for market participant 'k' at delivery point 'm' for generator failure 'f'; and F = the set of all generator failures 'f'.	Daily	Due MP	13	N/A	0	13	
1977 MRP new	Real-Time Intertie Offer Guarantee Uplift (RT_IOGU)	MR Ch.9 s.3.11	$$= \sum_{C}^{M,T} TD_{k,h,c}\,x \left[\sum^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t} + RQ_{k,h}^{m,i,t}) / \sum_{K}^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}) \right]$$ Where: C = the set of all charge types 'c' as follows: 1927.	Hourly	Due IESO	13	N/A	0	13	
1980 MRP new	Day-Ahead Market Reference Level Settlement Charge Uplift (DAM_RLSCU)	MR Ch.9 s.3.11	$$= \sum_{C}^{M,T} TD_{k,h,c}\,x \left[\sum^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t} + RQ_{k,h}^{m,i,t}) / \sum_{K}^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}) \right]$$ Where: C = the set of all charge types 'c' as follows: 1930.	Hourly	Due MP	13	N/A	0	13	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
1981 MRP new (RT_RLSCU)	Real-Time Reference Level Settlement Charge Uplift	MR Ch.9 s.3.11	$$= \sum_{C}^{M,T} TD_{k,h,c} \; x \left[\sum_{K}^{M,T}(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t} + RQ_{k,h}^{m,i,t}) / \sum_{K}^{M,T}(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}) \right]$$ Where: C = the set of all charge types 'c' as follows: 1931.	Hourly	Due MP	13	N/A	0	13	
1982 MRP new (EXP_PWSU)	Mitigation Amount for Physical Withholding Uplift	MR Ch.9 s.4.14.9	$$EXP\_PWSU_k = -1 \; x \sum_{K}^{M}(EXP\_PWSC_k^m) \times \left[\sum_{H}^{M,T}(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}) / \sum_{K,H}^{M,T}(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}) \right]$$ Where: $EXP\_PWSC_k^m$ = the mitigation for physical withholding settlement amount calculated for charge types 1932, 1933, 1934 and 1935 in accordance with MR Ch.9 s.5.4 for market participant 'k' at delivery point 'm'; and H = the set of all settlement hours 'h' in the relevant trading day.	Daily	Due MP	13	N/A	0	13	
1986 MRP new (EXP_EWSCU)	Mitigation Amount for Intertie Economic Withholding Uplift	MR Ch.9 s.4.14.10	$$EXP\_EWSCU_k = \sum_{K}^{M}(EXP\_EWSC_k^i) \times \left[\sum_{H}^{M,T}(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}) / \sum_{K,H}^{M,T}(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}) \right]$$ Where: $EXP\_EWSC_k^i$ = the mitigation for intertie economic withholding settlement amount calculated for charge types 1936, 1937, 1938 and 1939 in accordance with MR Ch.9 s.5.5 for market participant 'k' at intertie metering point 'i'; and H = the set of all settlement hours 'h' in the relevant trading day.	Daily	Due MP	13	N/A	0	13	
2148	Class B Global Adjustment Prior Period Correction Settlement Amount	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	

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
2470	MOE - Ontario Electricity Support Program Balancing Amount	N/A	$\Sigma_K TD_{k,1420}$ Where 'K' is the set of all market participants 'k'. Where $TD_{k,1420}$ 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.
9920	Adjustment Account Credit (AAC)	MR Ch.9 s.6.20.5.3	$AAD \times \Sigma_H{}^{M,T}\,[(AQEW_{k,h}{}^{m,t} + SQEW_{k,h}{}^{i,t}) / \Sigma_{K,H}{}^{M,T}\,(AQEW_{k,h}{}^{m,t} + SQEW_{k,h}{}^{i,t})]$ Where 'AAD' is the total dollar value of all disbursements from the IESO adjustment account authorized by the IESO Board in the current energy market billing period, in accordance with MR Ch.9 s.6 and expressed in up to 3 decimal places. Where 'H' is the set of all settlement 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' Where 'K' is the set of all market participants 'k'.	Monthly (when applicable)	Due MP	13	N/A	0	13	
9980	Smart Metering Charge	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	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	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	0	N/A	N/A	N/A	Implementation details subject to Ontario

Charge Type Number	Charge Type Name	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
	Settlement Amount		and (2) 33.2 per cent of the base invoice amount for market participant consumers who have an eligible account with the IESO		Providers and eligible MPs					Regulation 363/16 and 364/16
9984	COVID-19 Energy Assistance Program (CEAP) Balancing Amount	N/A	$\sum_K TD_{k,1477}$ Where 'K' is the set of all market participants 'k'. Where $TD_{k,1477}$ 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 OEB order EB-2020-0186 and EB-2020-0163
9990	IESO Administration Charge	MR Ch.9 s.4.3.1	$\sum_H^{M,T}(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t} + EGEI_k) \times TP$ 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.
9996	Recovery of Costs	MR Ch.2 App.3.4	Manual entry as per MR Ch.2 App.3.4	Monthly	Due IESO	13	N/A	N/A	N/A	

2.3. Rounding Conventions – by Charge Type

2.3.1. General Notes

- All *settlement amounts* reported by the *IESO settlements* system are expressed in dollars and are rounded to the nearest cent (e.g. 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.

- **Table 2-5** provides a description of each of the column references for rounding conventions by *charge type*.

- **Table 2-6** lists all the rounding conventions by *charge type*. This table:
  - 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 Specifications for Settlement Statement Files and Data Files document. This document is located on the Technical Interfaces webpage under 'Commercial Reconciliation';
  - 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*.

Table 2-5: Description of Column References for Rounding Conventions – by Individual Charge Type

Column Name	Description
Charge Type Number	This table contains an entry for each active *charge type* listed in section 2.2.
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.

Column Name	Description
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 <u>NOT</u> include the final rounding of *settlement amounts* to 2 decimal places as the last step in the calculation of ALL *charge types*.**
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.

Table 2-6: Rounding Conventions – by Individual Charge Type

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				
102	TR Clearing Account Credit	1	3	No				
104	Transmission Rights Settlement Credit	0	2	No				
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	3	No				
121	Northern Energy Advantage 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
123	MACD Enforcement Activity Amount	2	2	No				
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				
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				

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
164	Outage Cancellation/ Deferral Debit	1	3	No				
165	Unrecoverable Testing Costs Debit	1	3	No				
166	Tieline Maintenance Reliability Debit	1	3	No				
167	Emergency Energy Debit	1	3	No				
168	TR Market Shortfall Debit	1	3	No				
169	Station Service Reimbursement Debit	1	3	No				
171	Northern Energy Advantage Program Balancing Amount	1	3	No				
173	MACD Enforcement Activity Balancing Amount	2	2	No				
186	Intertie Failure Charge Uplift	1	3	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 djustment-Special Programs Balancing Amount	2	2	No				
199	Regulated Price Plan Retailer Balancing Amount	2	2	No				
201	10 Minute Spinning Reserve Market Shortfall Rebate	1	3	No				
203	10 Minute Non-spinning Reserve Market Shortfall Rebate	1	3	No				
205	30 Minute Operating Reserve Market Shortfall Rebate	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
206	10-Minute Spinning Non-Accessibility Settlement Amount	1	3	Yes	REAH = $TREAH_{r,k,h}^{M,t} \times \dfrac{EAH_{k,h}^{m,t}}{\sum^{M} EAH_{k,h}^{m,t}}$ Resulting Decimals: 3	Used to calculate adjusted operating reserve provided for aggregated generation resources		
208	10-Minute Non-Spinning Non-Accessibility Settlement Amount	1	3	Yes	REAH = $TREAH_{r,k,h}^{M,t} \times \dfrac{EAH_{k,h}^{m,t}}{\sum^{M} EAH_{k,h}^{m,t}}$ Resulting Decimals: 3	Used to calculate adjusted operating reserve provided for aggregated generation resources		
210	30-Minute Non-Accessibility Settlement Amount	1	3	Yes	REAH = $TREAH_{r,k,h}^{M,t} \times \dfrac{EAH_{k,h}^{m,t}}{\sum^{M} EAH_{k,h}^{m,t}}$ Resulting Decimals: 3	Used to calculate adjusted operating reserve provided for aggregated generation resources		
212	Day-Ahead Market 10-Minute Spinning Reserve Settlement Credit	1	3	No				
213	Real-Time 10-Minute Spinning Reserve Settlement Credit	1	3	No				
214	Day-Ahead Market 10-Minute Non-Spinning Reserve Settlement 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
215	Real-Time Market 10-Minute Non-Spinning Reserve Settlement Credit	1	3	No				
216	Day-Ahead Market 30-Minute Operating Reserve Settlement Credit	1	3	No				
217	Real-Time Market 30-Minute Operating Reserve Settlement Credit	1	3	No				
250	10-Minute Spinning Reserve Hourly Uplift	1	3	No				
251	10 Minute Spinning Market Reserve Shortfall Debit	1	3	No				
252	10-Minute Non-Spinning Reserve Hourly Uplift	1	3	No				
253	10 Minute Non-spinning Market Reserve Shortfall Debit	1	3	No				
254	30 Minute Operating Reserve Hourly 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
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				
410	IESO-Controlled Grid Special Operations Credit	2	2	No				
450	Black Start Capability Settlement Debit	1	3	No				
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				

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
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				
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				
703	Rural and Remote Settlement Credit	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
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				
750	Dispute Resolution Settlement Debit	2	2	No				
751	Dispute Resolution Board Service Debit	2	2	No				
753	Rural and Remote Settlement Debit	2	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				

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
900	GST/HST Credit	2	2	No				
950	GST/HST Debit	2	2	No				
1100	Day-Ahead Market Energy Settlement Amount for Generators	1	3	No				
1101	Real-Time Energy Settlement Amount for Generators	1	3	Yes	AQEI multiplied by 12 AQEW multiplied by 12 Resulting Decimals: 3 Numerator: BCQ Denominator: 12 Resulting Decimals: 3	AQEI or AQEW multiplied by RT_LMP. BCQ quantities multiplied by RT_LMP when applicable.		
1102	Day-Ahead Market Energy Settlement Amount for Dispatchable Loads	1	3	No				
1103	Real-Time Energy Settlement Amount for Dispatchable Loads	1	3	Yes	AQEI multiplied by 12 AQEW multiplied by 12 Resulting Decimals: 3 Numerator: BCQ Denominator: 12 Resulting Decimals: 3	AQEI or AQEW multiplied by RT_LMP. BCQ quantities multiplied by RT_LMP 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
1104	Day-Ahead Market Energy Settlement Amount for Price Responsive Loads	1	3	No				
1105	Real-Time Energy Settlement Amount for Price Responsive Loads	1	3	Yes	AQEW multiplied by 12 Resulting Decimals: 3 Numerator: BCQ Denominator: 12 Resulting Decimals: 3	AQEW quantity multiplied by RT_LMP. BCQ quantities multiplied by RT_LMP when applicable.		
1106	Day-Ahead Market Energy Settlement Amount for Virtual Transactions to Sell	1	3	No				
1107	Real-Time Energy Settlement Amount for Virtual Transactions to Sell	1	3	No				
1108	Day-Ahead Market Energy Settlement Amount for Virtual Transactions to Buy	1	3	No				
1109	Real-Time Energy Settlement Amount for Virtual Transactions to Buy	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
1110	Day-Ahead Market Energy Settlement Amount for Imports	1	3	No				
1111	Real-Time Energy Settlement Amount for Imports	1	3	Yes	Numerator: BCQ Denominator: 12 Resulting Decimals: 3	BCQ quantities multiplied by RT_LMP when applicable.		
1112	Day-Ahead Market Energy Settlement Amount for Exports	1	3	No				
1113	Real-Time Energy Settlement Amount for Exports	1	3	Yes	Numerator: BCQ Denominator: 12 Resulting Decimals: 3	BCQ quantities multiplied by RT_LMP when applicable.		
1115	Non-Dispatchable Load Energy Settlement Amount	1	3	Yes	AQEI multiplied by 12 AQEW multiplied by 12 Resulting Decimals: 3 Numerator: BCQ Denominator: 12 Resulting Decimals: 3	AQEI or AQEW multiplied by DAM_LMP. BCQ quantities multiplied by DAM_LMP when applicable.		
1116	Internal Congestion and Loss Residual	1	3	Yes	AQEI multiplied by 12 AQEW multiplied by 12 Resulting Decimals: 3	AQEI or AQEW multiplied by RT_LMP.		

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
1117	Day-Ahead Market Net External Congestion Residual	1	3	No				
1118	Real-Time External Congestion Residual Uplift	1	3	Yes	RT_ECR_L RT_ECR_E Resulting Decimals: 2	Distributed to either Loads or Exports.		
1119	Day-Ahead Market Net Interchange Scheduling Limit Residual Uplift	1	3	No				
1120	Real-Time Net Interchange Scheduling Limit Residual Uplift	1	3	No				
1138	Fuel Cost Compensation Credit	2	2	No				
1148	GA Energy Storage Injection Reimbursement	2	2	No				
1188	Fuel Cost Compensation Credit Uplift	1	3	No				
1314	Capacity Obligation – Availability Payment	1	3	No				
1315	Capacity Obligation – Availability 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
1316	Capacity Obligation – Administration Charge	1	3	No				
1317	Capacity Obligation – Dispatch Charge	1	3	No				
1318	Capacity Obligation – Capacity Charge	1	3	No				
1319	Capacity Obligation – Buy-Out Charge	1	3	No				
1320	Capacity Obligation – Dispatch Test Payment and Emergency 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 Cleared UCAP Adjustment Charge	1	3	No				
1324	Capacity Obligation – Availability Charge True-up Payment	1	3	No				

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1325	Capacity Obligation – Capacity Auction Charges True-up Payment	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				
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 OM&A Settlement Credit	1	2	No				
1405	Hourly Condense Energy Costs Settlement Credit	1	2	No				
1406	Monthly Condense Energy Costs Settlement 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
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				
1412	Feed-In Tariff Program Settlement Amount	1	3	No				
1413	Renewable Generation Connection – Monthly Compensation Amount Settlement Credit	1	3	No				
1414	Hydroelectric Contract Initiative Settlement Amount	1	3	No				
1416	Conservation and Demand Management - Compensation Settlement Credit	1	3	No				

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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				
1425	Hydroelectric Standard Offer Program Settlement Amount	2	2	No				
1450	OPA Contract Adjustment Balancing Amount	2	2	No				
1451	Incremental Loss Offset Settlement Amount	2	2	No				
1457	Ontario Electricity Rebate Balancing Amount	2	2	No				

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1460	Renewable 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 Amount Settlement Debit	1	3	No				
1464	Hydroelectric Contract Initiative Balancing Amount	2	2	No				
1466	Conservation and Demand Management - Compensation Balancing Amount	2	2	No				
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				

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1469	Energy from Waste (EFW) Contracts 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				
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				

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1800	Day-Ahead Market Make-Whole Payment – Energy Dispatchable Generation Resources	1	3	Yes	OP(DAM_LMP, DAM_QSI, DAM_BE) OP(DAM_LMP, DAM_EOP, DAM_BE) Resulting Decimals: 2 For Combustion Turbines: OP(DAM_LMP, DAM_QSI, DAM_DIPC) OP(DAM_LMP, DAM_EOP, DAM_DIPC) Resulting Decimals: 2 For Steam Turbines: OP(DAM_LMP, DAM_DIGQ, DAM_DIPC) OP(DAM_LMP, DAM_EOP_DIGQ, DAM_DIPC) Resulting Decimals: 2	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
1800	Day-Ahead Market Make-Whole Payment – Energy Hydroelectric Generation Resources Not Associated with Linked Forebays	1	3	Yes	OP(DAM_LMP, DAM_QSI, DAM_BE) OP(DAM_LMP,DAM_EOP, DAM_BE) Forbidden Region Operating Profit: OP(DAM_LMP, FR_UL, DAM_BE) OP(DAM_LMP, MAX(DAM_EOP, FR_LL), DAM_BE) Resulting Decimals: 2	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
1800	Day-Ahead Market Make-Whole Payment – Energy Hydroelectric Generation Resources Associated with Linked Forebays	1	3	Yes	OP(DAM_LMP, DAM_QSI, DAM_BE) OP(DAM_LMP, DAM_EOP, DAM_BE) Forbidden Region Operating Profit: OP(DAM_LMP, FR_UL, DAM_BE) OP(DAM_LMP, MAX(DAM_EOP, FR_LL), DAM_BE) Resulting Decimals: 2	Profits are compared as applicable.		
1800	Day-Ahead Market Make-Whole Payment – Energy Dispatchable Loads	1	3	Yes	OP(DAM_LMP, DAM_QSW, DAM_BL) OP(DAM_LMP, DAM_EOP, DAM_BL) Resulting Decimals: 2	Profits are compared as applicable.		

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1800	Day-Ahead Market Make-Whole Payment – Energy Non-HDR Price Responsive Loads	1	3	Yes	OP(DAM_LMP, DAM_QSW, DAM_BL) OP(DAM_LMP, DAM_EOP, DAM_BL) Resulting Decimals: 2	Profits are compared as applicable.		
1800	Day-Ahead Market Make-Whole Payment – Energy Physical Hourly Demand Response Price Responsive Loads	1	3	Yes	OP(DAM_LMP, DAM_QSW, DAM_BL) OP(DAM_LMP, DAM_EOP, DAM_BL) OP(DAM_LMP, DAM_HDR_QSW, DAM_HDR_BL) OP(DAM_LMP, DAM_EOP, DAM_HDR_BL) Resulting Decimals: 2	Profits are compared as applicable.		
1800	Day-Ahead Market Make-Whole Payment – Energy Boundary Entity Resource – Imports	1	3	Yes	OP(DAM_LMP, DAM_QSI, DAM_BE) OP(DAM_LMP, DAM_EOP, DAM_BE) Resulting Decimals: 2	Profits are compared as applicable.		

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1800	Day-Ahead Market Make-Whole Payment – Energy Boundary Entity Resource – Exports	1	3	Yes	OP(DAM_LMP, DAM_QSW, DAM_BL) OP(DAM_LMP, DAM_EOP, DAM_BL) Resulting Decimals: 2	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
1801	Day-Ahead Market Make-Whole Payment – 10-Minute Spinning Reserve Dispatchable Generation Resources	1	3	Yes	OP(DAM_PROR, DAM_QSOR, DAM_BOR) OP(DAM_PROR, DAM_OR_EOP, DAM_BOR) For Combustion Turbines: OP(DAM_PROR, DAM_QSOR, DAM_OR_DIPC) OP(DAM_PROR, DAM_OR_EOP, DAM_OR_DIPC) For Steam Turbines: OP(DAM_PROR, DAM_QSOR, DAM_OR_DIPC) OP(DAM_PROR, DAM_OR_EOP, DAM_OR_DIPC) Resulting Decimals: 2	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
1801	Day-Ahead Market Make-Whole Payment – 10-Minute Spinning Reserve Hydroelectric Generation Resources not Associated with Linked Forebays	1	3	Yes	OP(DAM_PROR, DAM_QSOR, DAM_BOR) OP(DAM_PROR, DAM_OR_EOP, DAM_BOR) Resulting Decimals: 2	Profits are compared as applicable.		
1801	Day-Ahead Market Make-Whole Payment – 10-Minute Spinning Reserve Hydroelectric Generation Resources Associated with Linked Forebays	1	3	Yes	OP(DAM_PROR, DAM_QSOR, DAM_BOR) OP(DAM_PROR, DAM_OR_EOP, DAM_BOR) Resulting Decimals: 2	Profits are compared as applicable.		
1801	Day-Ahead Market Make-Whole Payment – 10-Minute Spinning Reserve Dispatchable Loads	1	3	Yes	OP(DAM_PROR, DAM_QSOR, DAM_BOR) OP(DAM_PROR, DAM_OR_EOP, DAM_BOR) Resulting Decimals: 2	Profits are compared as applicable.		

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1802	Day-Ahead Market Make-Whole Payment – 10-Minute Non-Spinning Reserve Dispatchable Generation Resources	1	3	Yes	OP(DAM_PROR, DAM_QSOR, DAM_BOR) OP(DAM_PROR, DAM_OR_EOP, DAM_BOR) For Combustion Turbines: OP(DAM_PROR, DAM_QSOR, DAM_OR_DIPC) OP(DAM_PROR, DAM_OR_EOP, DAM_OR_DIPC) For Steam Turbines: OP(DAM_PROR, DAM_QSOR, DAM_OR_DIPC) OP(DAM_PROR, DAM_OR_EOP, DAM_OR_DIPC) Resulting Decimals: 2	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
1802	Day-Ahead Market Make-Whole Payment – 10-Minute Non-Spinning Reserve Hydroelectric Generation Resources not Associated with Linked Forebays	1	3	Yes	OP(DAM_PROR, DAM_QSOR, DAM_BOR) OP(DAM_PROR, DAM_OR_EOP, DAM_BOR) Resulting Decimals: 2	Profits are compared as applicable.		
1802	Day-Ahead Market Make-Whole Payment – 10-Minute Non-Spinning Reserve Hydroelectric Generation Resources Associated with Linked Forebays	1	3	Yes	OP(DAM_PROR, DAM_QSOR, DAM_BOR) OP(DAM_PROR, DAM_OR_EOP, DAM_BOR) Resulting Decimals: 2	Profits are compared as applicable.		
1802	Day-Ahead Market Make-Whole Payment – 10-Minute Non-Spinning Reserve Dispatchable Loads	1	3	Yes	OP(DAM_PROR, DAM_QSOR, DAM_BOR) OP(DAM_PROR, DAM_OR_EOP, DAM_BOR) Resulting Decimals: 2	Profits are compared as applicable.		

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1802	Day-Ahead Market Make-Whole Payment – 10-Minute Non-Spinning Reserve Boundary Entity Resources - Imports	1	3	Yes	OP(DAM_PROR, DAM_QSOR, DAM_BOR) OP(DAM_PROR, DAM_OR_EOP, DAM_BOR) Resulting Decimals: 2	Profits are compared as applicable.		
1802	Day-Ahead Market Make-Whole Payment – 10-Minute Non-Spinning Reserve Boundary Entity Resources - Exports	1	3	Yes	OP(DAM_PROR, DAM_QSOR, DAM_BOR) OP(DAM_PROR, DAM_OR_EOP, DAM_BOR) Resulting Decimals: 2	Profits are compared as applicable.		

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1803	Day-Ahead Market Make-Whole Payment – 30-Minute Operating Reserve Dispatchable Generation Resources	1	3	Yes	OP(DAM_PROR, DAM_QSOR, DAM_BOR) OP(DAM_PROR, DAM_OR_EOP, DAM_BOR) For Combustion Turbines: OP(DAM_PROR, DAM_QSOR, DAM_OR_DIPC) OP(DAM_PROR, DAM_OR_EOP, DAM_OR_DIPC) For Steam Turbines: OP(DAM_PROR, DAM_QSOR, DAM_OR_DIPC) OP(DAM_PROR, DAM_OR_EOP, DAM_OR_DIPC) Resulting Decimals: 2	Profits are compared as applicable.		

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1803	Day-Ahead Market Make-Whole Payment – 30-Minute Operating Reserve Hydroelectric Generation Resources not Associated with Linked Forebays	1	3	Yes	OP(DAM_PROR, DAM_QSOR, DAM_BOR) OP(DAM_PROR, DAM_OR_EOP, DAM_BOR) Resulting Decimals: 2	Profits are compared as applicable.		
1803	Day-Ahead Market Make-Whole Payment – 30-Minute Operating Reserve Hydroelectric Generation Resources Associated with Linked Forebays	1	3	Yes	OP(DAM_PROR, DAM_QSOR, DAM_BOR) OP(DAM_PROR, DAM_OR_EOP, DAM_BOR) Resulting Decimals: 2	Profits are compared as applicable.		
1803	Day-Ahead Market Make-Whole Payment – 30-Minute Operating Reserve Dispatchable Loads	1	3	Yes	OP(DAM_PROR, DAM_QSOR, DAM_BOR) OP(DAM_PROR, DAM_OR_EOP, DAM_BOR) Resulting Decimals: 2	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
1803	Day-Ahead Market Make-Whole Payment – 30-Minute Operating Reserve Boundary Entity Resources - Imports	1	3	Yes	OP(DAM_PROR, DAM_QSOR, DAM_BOR) OP(DAM_PROR, DAM_OR_EOP, DAM_BOR) Resulting Decimals: 2	Profits are compared as applicable.		
1803	Day-Ahead Market Make-Whole Payment – 30-Minute Operating Reserve Boundary Entity Resources - Exports	1	3	Yes	OP(DAM_PROR, DAM_QSOR, DAM_BOR) OP(DAM_PROR, DAM_OR_EOP, DAM_BOR) Resulting Decimals: 2	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
1804	Day-Ahead Generator Offer Guarantee – Energy	1	3	Yes	OP(DAM_LMP, DAM_QSI, DAM_BE) (DAM_LMP x DAM_QSI) For Combustion Turbines: OP(DAM_LMP, DAM_QSI, DAM_DIPC) For Steam Turbines: OP(DAM_LMP, DAM_DIGQ, DAM_DIPC) Resulting Decimals: 2	Profits are compared as applicable.		
1805	Day-Ahead Generator Offer Guarantee – Operating Reserve	1	3	Yes	OP(DAM_PROR, DAM_QSOR, DAM_BOR) For Combustion Turbines: OP(DAM_PROR, DAM_QSOR, DAM_OR_DIPC) For Steam Turbines: OP(DAM_PROR, DAM_QSOR, DAM_OR_DIPC) Resulting Decimals: 2	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
1806	Day-Ahead Market Generator Offer Guarantee – Over Midnight	1	3	Yes	OP(DAM_LMP, MLP, DAM_BE) For Combustion Turbines: OP(DAM_LMP, MLP, DAM_DIPC) For Steam Turbines: OP(DAM_LMP, MLP, DAM_DIPC) Resulting Decimals: 2	Profits are compared as applicable.		
1807	Day-Ahead Market Generator Offer Guarantee – Start-up	1	2	No				
1808	Day-Ahead Market Generator Offer Guarantee – DAM Make-Whole Payment Offset	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
1815	Day-Ahead Market Balancing Credit - Energy	1	3	Yes	AQEI multiplied by 12 Resulting Decimals: 3	Deduct from DAM_QSI	For import transactions: OP(RT_LMP, Min(RT_LOC_EOP, DAM_QSI), BE) OP(RT_LMP, SQEI, BE) For export transactions: OP(RT_LMP, Min(RT_LOC_EOP, DAM_QSW), BL) OP(RT_LMP, SQEW, BL) Resulting Decimals: 2	Profits are compared as applicable.
1816	Day-Ahead Market Balancing Credit – Operating Reserve	1	3	Yes	OP(RT_PROR, Min(RT_OR_LOC_EOP, DAM_QSOR), BOR) OP(RT_PROR, RT_QSOR, BOR) Resulting Decimals: 2	Profits are compared as applicable.		
1828	Day-Ahead Market Import Failure Charge	1	3	No				
1829	Day-Ahead Market Export Failure Charge	1	3	No				
1830	Tariff Response Charge for Exports	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
1850	Day-Ahead Market Uplift	1	3	No				
1851	Day-Ahead Market Reliability Scheduling Uplift	1	3	Yes	DAM_P2_PMT V_DRSU Resulting Decimals: 2	Subtracted from each other to determine the amount of uplift to be apportioned to exports and loads		
1852	Day-Ahead Market Reliability Scheduling Uplift – Virtual Transactions to Sell	1	3	Yes	Pass 1: OP(DAM_LMP, DAM_QSI, DAM_BE) OP(DAM_LMP, DAM_EOP_OR, DAM_BE) Pass 2: OP(DAM_LMP, DAM_QSI, DAM_BE) OP(DAM_LMP, DAM_EOP_OR, DAM_BE) Resulting Decimals: 2	Subtracted from each other to calculate the DAM_MWP in Pass 1 & Pass 2		
1865	Day-Ahead Market Balancing Credit 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
1880	Tariff Response Charge for Exports Balancing Amount	1	3	No				
1900	Real-Time Make-Whole Payment – Lost Cost for Energy Dispatchable Generation Resources	1	3	Yes	AQEI multiplied by 12 Resulting Decimals: 3	Compare with RT_QSI	OP(RT_LMP, Max(DAM_QSI, MIN(RT_QSI,AQEI)), BE) OP(RT_LMP, Max(RT_LC_EOP, DAM_QSI), BE) Forbidden Region Operating Profit: OP(RT_LMP, Max(DAM_QSI, MIN(RT_QSI,AQEI)), BE) OP(RT_LMP, Max(FR_LL, RT_LC_EOP, DAM_QSI), BE) For Combustion Turbines: OP(RT_LMP, Max(DAM_QSI, MIN(RT_QSI,AQEI)), RT_DIPC) OP(RT_LMP, Max(RT_LC_EOP, DAM_QSI), RT_DIPC) For Steam Turbines: OP(RT_LMP, Max(DAM_DIGQ,	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
							MIN(RT_QSI_DIGQ, AQEI)), RT_DIPC) OP(RT_LMP, Max(RT_LC_EOP_DIGQ, DAM_DIGQ), RT_DIPC) Resulting Decimals: 2	
1900	Real-Time Make-Whole Payment – Lost Cost for Energy Dispatchable Loads	1	3	Yes	AQEW multiplied by 12 Resulting Decimals: 3	Compare with RT_QSW	OP(RT_LMP, MAX(DAM_QSW, MIN(RT_QSW, AQEW)), BL) OP(RT_LMP, Max(RT_LC_EOP, DAM_QSW), BL) Resulting Decimals: 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
1900	Real-Time Make-Whole Payment – Lost Cost for Energy Boundary Entity Resources - Exports	1	3	Yes	OP(RT_LMP, MAX(SQEW, DAM_QSW), BL) OP(RT_LMP, Max(RT_LC_EOP, DAM_QSW), BL) OP(MIN(RT_LMP, PD_LMP), MAX(SQEW, DAM_QSW), BL) OP(MIN(RT_LMP, PD_LMP), Max(RT_LC_EOP, DAM_QSW), BL) Resulting Decimals: 2	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
1901	Real-Time Make-Whole Payment – Lost Cost for 10-Minute Spinning Reserve Dispatchable Generation Resources	1	3	Yes	OP(RT_PROR, Max(DAM_QSOR, RT_QSOR), BOR) OP(RT_PROR, Max(RT_OR_LC_EOP, DAM_QSOR), BOR) For Combustion Turbines: OP(RT_PROR, Max(DAM_QSOR, RT_QSOR), RT_OR_DIPC) OP(RT_PROR, Max(RT_OR_LC_EOP, DAM_QSOR), RT_OR_DIPC) For Steam Turbines: OP(RT_PROR, Max(DAM_QSOR, RT_QSOR), RT_OR_DIPC) OP(RT_PROR, Max(RT_OR_LC_EOP, DAM_QSOR), RT_OR_DIPC) Resulting Decimals: 2	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
1901	Real-Time Make-Whole Payment – Lost Cost for 10-Minute Spinning Reserve Dispatchable Loads	1	3	Yes	OP(RT_PROR, Max(DAM_QSOR, RT_QSOR), BOR) OP(RT_PROR, Max(RT_OR_LC_EOP, DAM_QSOR), BOR) Resulting Decimals: 2	Profits are compared as applicable.		
1902	Real-Time Make-Whole Payment – Lost Cost for 10-Minute Non-Spinning Reserve Dispatchable Generation Resources	1	3	Yes	OP(RT_PROR, Max(DAM_QSOR, RT_QSOR), BOR) OP(RT_PROR, Max(RT_OR_LC_EOP, DAM_QSOR), BOR) For Combustion Turbines: OP(RT_PROR, Max(DAM_QSOR, RT_QSOR), RT_OR_DIPC) OP(RT_PROR, Max(RT_OR_LC_EOP, DAM_QSOR), RT_OR_DIPC) For Steam Turbines:	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(RT_PROR, Max(DAM_QSOR, RT_QSOR), RT_OR_DIPC) OP(RT_PROR, Max(RT_OR_LC_EOP, DAM_QSOR), RT_OR_DIPC) Resulting Decimals: 2			
1902	Real-Time Make-Whole Payment – Lost Cost for 10-Minute Non-Spinning Reserve Dispatchable Loads	1	3	Yes	OP(RT_PROR, Max(DAM_QSOR, RT_QSOR), BOR) OP(RT_PROR, Max(RT_OR_LC_EOP, DAM_QSOR), BOR) Resulting Decimals: 2	Profits are compared as applicable.		
1902	Real-Time Make-Whole Payment – Lost Cost for 10-Minute Non-Spinning Reserve Boundary Entity Resources - Exports	1	3	Yes	OP(RT_PROR, Max(DAM_QSOR, RT_QSOR), BOR) OP(RT_PROR, Max(RT_OR_LC_EOP, DAM_QSOR), BOR) Resulting Decimals: 2	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
1902	Real-Time Make-Whole Payment – Lost Cost for 10-Minute Non-Spinning Reserve Boundary Entity Resources - Imports	1	3	Yes	OP(RT_PROR, Max(DAM_QSOR, RT_QSOR), BOR) OP(RT_PROR, Max(RT_OR_LC_EOP, DAM_QSOR), BOR) Resulting Decimals: 2	Profits are compared as applicable.		
1903	Real-Time Make-Whole Payment – Lost Cost for 30-Minute Operating Reserve Dispatchable Generation Resources	1	3	Yes	OP(RT_PROR, Max(DAM_QSOR, RT_QSOR), BOR) OP(RT_PROR, Max(RT_OR_LC_EOP, DAM_QSOR), BOR) For Combustion Turbines: OP(RT_PROR, Max(DAM_QSOR, RT_QSOR), RT_OR_DIPC) OP(RT_PROR, Max(RT_OR_LC_EOP, DAM_QSOR), RT_OR_DIPC) For Steam Turbines:	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(RT_PROR, Max(DAM_QSOR, RT_QSOR), RT_OR_DIPC) OP(RT_PROR, Max(RT_OR_LC_EOP, DAM_QSOR), RT_OR_DIPC) Resulting Decimals: 2			
1903	Real-Time Make-Whole Payment – Lost Cost for 30-Minute Operating Reserve Dispatchable Loads	1	3	Yes	OP(RT_PROR, Max(DAM_QSOR, RT_QSOR), BOR) OP(RT_PROR, Max(RT_OR_LC_EOP, DAM_QSOR), BOR) Resulting Decimals: 2	Profits are compared as applicable.		
1903	Real-Time Make-Whole Payment – Lost Cost for 30-Minute Operating Reserve Boundary Entity Resources - Exports	1	3	Yes	OP(RT_PROR, Max(DAM_QSOR, RT_QSOR), BOR) OP(RT_PROR, Max(RT_OR_LC_EOP, DAM_QSOR), BOR) Resulting Decimals: 2	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
1903	Real-Time Make-Whole Payment – Lost Cost for 30-Minute Operating Reserve Boundary Entity Resources - Imports	1	3	Yes	OP(RT_PROR, Max(DAM_QSOR, RT_QSOR), BOR) OP(RT_PROR, Max(RT_OR_LC_EOP, DAM_QSOR), BOR) Resulting Decimals: 2	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
1904	Real-Time Make-Whole Payment – Lost Opportunity Cost for Energy Dispatchable Generation Resources	1	3	Yes	AQEI multiplied by 12 Resulting Decimals: 3	Compare with RT_QSI.	OP(RT_LMP, RT_LOC_EOP, BE) OP(RT_LMP, Max(RT_QSI, AQEI), BE) FROP = OP(RT_LMP, Min(FR_UL, RT_LOC_EOP), BE) - OP(RT_LMP, Max(RT_QSI, AQEI), BE) For Combustion Turbines: OP(RT_LMP, RT_LOC_EOP, RT_DIPC) OP(RT_LMP, Max(RT_QSI,AQEI), RT_DIPC) For Steam Turbines: OP(RT_LMP, RT_LOC_EOP_DIGQ, RT_DIPC) OP(RT_LMP, Max(RT_QSI_DIGQ, AQEI), RT_DIPC) OP(RT_LMP, RT_QSI_DIGQ, RT_DIPC) Resulting Decimals: 2	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
1904	Real-Time Make-Whole Payment – Lost Opportunity Cost for Energy Dispatchable Loads	1	3	Yes	AQEW multiplied by 12 Resulting Decimals: 3	Compare with RT_QSW.	OP(RT_LMP, RT_LOC_EOP, BL) OP(RT_LMP, Max(RT_QSW, AQEW), BL) Resulting Decimals: 2	Profits are compared as applicable.
1905	Real-Time Make-Whole Payment – Lost Opportunity Cost for 10-Minute Spinning Reserve Dispatchable Generation Resources	1	3	Yes	OP(RT_PROR, RT_OR_LOC_EOP, BOR) OP(RT_PROR, RT_QSOR, BOR) For Combustion Turbines: OP(RT_PROR, RT_OR_LOC_EOP, RT_OR_DIPC) OP(RT_PROR, RT_QSOR, RT_OR_DIPC) For Steam Turbines: OP(RT_PROR, RT_OR_LOC_EOP, RT_OR_DIPC) OP(RT_PROR, RT_QSOR, RT_OR_DIPC)	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
					Resulting Decimals: 2			
1905	Real-Time Make-Whole Payment – Lost Opportunity Cost for 10-Minute Spinning Reserve Dispatchable Loads	1	3	Yes	OP(RT_PROR, RT_OR_LOC_EOP, BOR) OP(RT_PROR, RT_QSOR, BOR) Resulting Decimals: 2	Profits are compared as applicable.		
1906	Real-Time Make-Whole Payment – Lost Opportunity Cost for 10-Minute Non-Spinning Reserve Dispatchable Generation Resources	1	3	Yes	OP(RT_PROR, RT_OR_LOC_EOP, BOR) OP(RT_PROR, RT_QSOR, BOR) For Combustion Turbines: OP(RT_PROR, RT_OR_LOC_EOP, RT_OR_DIPC) OP(RT_PROR, RT_QSOR, RT_OR_DIPC) For Steam Turbines: OP(RT_PROR, RT_OR_LOC_EOP, RT_OR_DIPC)	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(RT_PROR, RT_QSOR, RT_OR_DIPC)\n\nResulting Decimals: 2			
1906	Real-Time Make-Whole Payment – Lost Opportunity Cost for 10-Minute Non-Spinning Reserve\n\nDispatchable Loads	1	3	Yes	OP(RT_PROR, RT_OR_LOC_EOP, BOR)\n\nOP(RT_PROR, RT_QSOR, BOR)\n\nResulting Decimals: 2	Profits are compared as applicable.		
1907	Real-Time Make-Whole Payment – Lost Opportunity Cost for 30-Minute Operating Reserve\n\nDispatchable Generation Resources	1	3	Yes	OP(RT_PROR, RT_OR_LOC_EOP, BOR)\n\nOP(RT_PROR, RT_QSOR, BOR)\n\nFor Combustion Turbines:\nOP(RT_PROR, RT_OR_LOC_EOP, RT_OR_DIPC)\n\nOP(RT_PROR, RT_QSOR, RT_OR_DIPC)\n\nFor Steam Turbines:\nOP(RT_PROR, RT_OR_LOC_EOP, RT_OR_DIPC)	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(RT_PROR, RT_QSOR, RT_OR_DIPC) Resulting Decimals: 2			
1907	Real-Time Make-Whole Payment – Lost Opportunity Cost for 30-Minute Operating Reserve Dispatchable Loads	1	3	Yes	OP(RT_PROR, RT_OR_LOC_EOP, BOR) OP(RT_PROR, RT_QSOR, BOR) Resulting Decimals: 2	Profits are compared as applicable.		

| 1908 | Real-Time Make-Whole Payment - Operating Reserve Non-Accessibility Lost Cost Reversal | 1 | 3 | Yes | For 10S:
OP(RT_PROR_R1, MAX(DAM_QSOR_R1, RT_QSOR_R1), BOR_R1)

OP(RT_PROR_R1, Max(TAOR, RT_OR_LC_EOP_R1, DAM_QSOR_R1), BOR_R1)

Resulting Decimals: 2

For 10N:
OP(RT_PROR_R2, MAX(DAM_QSOR_R2, RT_QSOR_R2), BOR_R2)

OP(RT_PROR_R2, Max(TAOR-RT_QSOR_R1, RT_OR_LC_EOP_R2, DAM_QSOR_R2) BOR_R2)

Resulting Decimals: 2

For 30N:
OP(RT_PROR_R3, MAX(DAM_QSOR_R3, RT_QSOR_R3), BOR_R3)

OP(RT_PROR_R3, Max(TAOR-RT_QSOR_R1-RT_QSOR_R2, RT_OR_LC_EOP_R3, DAM_QSOR_R3), BOR_R3) | 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
					Resulting Decimals: 2			

| 1909 | Real-Time Make-Whole Payment - Operating Reserve Non-Accessibility Lost Opportunity Cost Reversal | 1 | 3 | Yes | For 10S:
OP(RT_PROR_R1, RT_OR_LOC_EOP_R1, RT_OR_DIPC_R1)

OP(RT_PROR_R1, Max(RT_QSOR_R1, TAOR_CT) RT_OR_DIPC_R1)

Resulting Decimals: 2

For 10N:
OP(RT_PROR_R2, RT_OR_LOC_EOP_R2, RT_OR_DIPC_R2)

OP(RT_PROR_R2, Max(TAOR-RT_QSOR_R1, RT_QSOR_R2), RT_OR_DIPC_R2)

Resulting Decimals: 2

For 30N:
OP(RT_PROR_R3, RT_OR_LOC_EOP_R3, RT_OR_DIPC_R3)

OP(RT_PROR_R3, MAX(RT_QSOR_R3, TAOR-RT_QSOR_R1-RT_QSOR_R2), BOR_R3)

Resulting Decimals: 2 | 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
1910	Real-Time Generator Offer Guarantee - Energy	1	3	Yes	AQEI multiplied by 12 Resulting Decimals: 3	Operating profit calculation.	OP(RT_LMP, RT_QSI, BE) OP(RT_LMP, AQEI, BE) RT_LMP x AQEI DAM_LMP x DAM_QSI Resulting Decimals: 2	Profits are compared as applicable.
1911	Real-Time Generator Offer Guarantee – Operating Reserve	1	3	Yes	OP(RT_PROR, RT_QSOR, BOR) Resulting Decimals: 2			
1912	Real-Time Generator Offer Guarantee – Over Midnight	1	3	Yes	OP(RT_LMP, MLP, BE) Resulting Decimals: 2			
1913	Real-Time Generator Offer Guarantee – Start-up	1	2	No				
1914	Real-Time Generator Offer Guarantee – RT Make-Whole Payment Offset	1	2	No				

| 1915 | Real-Time Generator Offer Guarantee – Operating Reserve Non-Accessibility Reversal | 1 | 3 | Yes | For 10S:
OP(RT_PROR_R1, RT_QSOR_R1, BOR_R1)

OP(RT_PROR_R1, TAOR, BOR_R1)
Resulting Decimals: 2

For 10N:
OP(RT_PROR_R2, RT_QSOR_R2, BOR_R2)

OP(RT_PROR_R2, TAOR-T_QSOR_R1, BOR_R2)
Resulting Decimals: 2

For 30N:
OP(RT_PROR_R3, RT_QSOR_R3, BOR_R3)

OP(RT_PROR_R3, TAOR-T_QSOR_R1-RT_QSOR_R2, BOR_R3)
Resulting Decimals: 2

For ST Case:
ORSCB_REV= -1 x ORSCB x (RT_OR_CMT_DIGQ/RT_QSOR)
Resulting Decimals: 2

RT_GOG_TAOR_ST= TAOR_ST x (RT_OR_CMT_DIGQ/RT_QSOR)
Resulting Decimals: 3 | 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
					ORIA_AMT For 10S: RT_PROR_R1 (RT_QSOR_R1-TAOR) Resulting Decimals: 2 For 10N: RT_PROR_R2 (RT_QSOR_R2-MAX(0, TAOR-RT_QSOR_R1)) Resulting Decimals: 2 For 30N: RT_PROR_R3 (RT_QSOR_R3-MAX(0, TAOR-RT_QSOR_R1-RT_QSOR_R2)) Resulting Decimals: 2			
1917	Real-Time Ramp-Down Settlement Amount	1	3	Yes	OP(DAM_LMP, AQEI, BE) OP(DAM_LMP, AQEI, DAM_BE) OP(RT_LMP, AQEI, BE) Resulting Decimals: 2	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
1920	Generator Failure Charge – Market Price Component	1	3	No				
1921	Generator Failure Charge – Guarantee Cost Component	1	3	Yes	Numerator: PD_BE_SNL Denominator: 12 Resulting Decimals: 2 PD_SU_Ratio Resulting Decimals: 5	Sum to the GCC amount.	M1 Resulting Decimals: 5	Multiplied by the GCC amount.
1927	Real-Time Intertie Offer Guarantee	1	3	No				
1928	Real-Time Import Failure Charge	1	3	No				
1929	Real-Time Export Failure Charge	1	3	No				
1930	Day-Ahead Market Reference Level Settlement Charge	1	2	No				
1931	Real-Time Reference Level Settlement Charge	1	2	No				
1932	Mitigation Amount for Physical Withholding - Energy	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
1933	Mitigation Amount for Physical Withholding – 10S Operating Reserve	1	3	No				
1934	Mitigation Amount for Physical Withholding – 10N Operating Reserve	1	3	No				
1935	Mitigation Amount for Physical Withholding – 30R Operating Reserve	1	3	No				
1936	Mitigation Amount for Intertie Economic Withholding - Energy	1	3	No				
1937	Mitigation Amount for Intertie Economic Withholding – 10N Operating Reserve	1	3	No				
1938	Mitigation Amount for Intertie Economic Withholding – 30R Operating Reserve	1	3	No				
1939	Mitigation Amount for Intertie Economic Withholding – Make-Whole Payment	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
1950	Real-Time Make-Whole Payment Uplift	1	3	No				
1960	Real-Time Generator Offer Guarantee Uplift	1	3	No				
1967	Real-Time Ramp-Down Settlement Amount Uplift	1	3	No				
1970	Generator Failure Charge – Market Price Component Uplift	1	3	No				
1971	Generator Failure Charge – Guarantee Cost Component Uplift	1	3	No				
1977	Real-Time Intertie Offer Guarantee Uplift	1	3	No				
1980	Day-Ahead Market Reference Level Settlement Charge Uplift	1	3	No				
1981	Real-Time Reference Level Settlement Charge 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
1982	Mitigation Amount for Physical Withholding Uplift	1	3	No				
1986	Mitigation Amount for Intertie Economic Withholding Uplift	1	3	No				
2148	Class B Global Adjustment Prior Period Correction Settlement Amount	2	2	No				
2470	MOE - Ontario Electricity Support Program Balancing Amount	2	2	No				
9920	Adjustment Account Credit	1	1	No				
9980	Smart Metering Charge	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				

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
9996	Recovery of Costs	2	2	No				

2.4. Settlement of Physical Bilateral Contracts

2.4.1. Market Price of Energy Applied to Location of Physical Bilateral Contract

(MR Ch.8 s. 2.1)

The *settlement process* will apply the applicable *market price* for *energy* according to the location of the *physical bilateral contract* in accordance with **MR Ch.8 s.2.1.3.2** and is summarized in the following tables for each timeframe**.**

Table 2-7: Day-Ahead Market: Market Price of Energy Applied to Location of Physical Bilateral Contract

Location of Physical Bilateral Contract	Settlement of Selling Market Participant **Debit** the *physical bilateral contract quantity* of *energy* sold at the…	Settlement of Buying Market Participant **Credit** the *physical bilateral contract quantity* of *energy* bought at the…	Charge Type
Non-dispatchable *delivery point* – *generation resource*	N/A	N/A	N/A
Non-dispatchable *delivery point* – *load resource*	N/A	N/A	N/A
Price responsive loads *Self-scheduling electricity storage resources*	$DAM\_LMP_h^m$	$DAM\_LMP_h^m$	*Charge Type* 1104
Dispatchable *delivery point* • *generation resource* • *electricity storage resource* (injecting or withdrawing) • *dispatchable load*	$DAM\_LMP_h^m$	$DAM\_LMP_h^m$	*Charge type* 1100 1102
Intertie metering point	$DAM\_LMP_h^i$	$DAM\_LMP_h^i$	*Charge type* 1110 1112

Table 2-8: Real-Time Market: Market Price of Energy Applied to Location of Physical Bilateral Contract

Location of Physical Bilateral Contract	Settlement of Selling Market Participant **Debit** the *physical bilateral contract quantity* of *energy* sold at the…	Settlement of Buying Market Participant **Credit** the *physical bilateral contract quantity* of *energy* bought at the…	Charge Type
Non-dispatchable *delivery point – load resource*	$DAM\_LMP_h^z$	$DAM\_LMP_h^z$	*Charge type* 1115
Price responsive loads *Self-scheduling electricity storage resources*	$RT\_LMP_h^{m,t}$	$RT\_LMP_h^{m,t}$	*Charge type* 1105
Dispatchable *delivery point* • *generation resource* • *electricity storage resource (injecting or withdrawing)* • *dispatchable load*	$RT\_LMP_h^{m,t}$	$RT\_LMP_h^{m,t}$	*Charge type* 1101 1103
Intertie metering point	$RT\_LMP_h^{i,t}$	$RT\_LMP_h^{i,t}$	*Charge type* 1111 1113

These *settlement* debits and credits are included in the overall *settlement amounts* calculated for the *energy charge types* noted in the tables above under the two-*settlement* system, in accordance with **MR Ch.9 s.3.1-3.2**.

2.4.2.   The Nature of the Bilateral Contract Quantity

(MR Ch.8 s.2.3)

Physical bilateral contract data, submitted by *selling market participants* to the *IESO* in the *day-ahead market* and/or *real-time market* must contain the information in accordance with MR Ch.8 s.2.2. *Selling market participants* shall submit *physical bilateral contract data* for the same *delivery point* or *intertie metering point* on the same *trading day* in one of the two following forms in accordance with **MR Ch.8 s.2.3**:

1. absolute quantities of *energy*, as described in **MR Ch.8 s.2.3.1.2**; and

2. derived quantity of *energy*, as described in **MR Ch.8 s.2.3.1.1**.

The derived quantity of *energy* option is only available for *real-time market physical bilateral contracts* and where one of the two parties to the *physical bilateral contract* is the *metered market participant* for the *registered wholesale meter* associated with the *delivery point*.

The following examples illustrate the submission of *physical bilateral contract data* using the derived quantity of *energy*, 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;* and

- quantities of *energy* in the *physical bilateral contract data* are total quantities of *energy* for each *settlement hour* and not quantities of *energy* for *metering intervals* within the *settlement hour*.

Table 2-9: Derived Quantities Example 1

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											

Table 2-10: Derived Quantities Example 2

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											

Table 2-11: Derived Quantities Example 3

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											

Table 2-12: Derived Quantities Example 4

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											

2.4.3. Allocation of Hourly Uplift Components Between Buying and Selling Market Participants

The *settlement process* will collect *physical bilateral contract data* in accordance with **MR Ch.9 s.2.7**, and for each *physical bilateral contract data,* the *settlement process* will allocate *hourly uplift* components assigned to the *selling market participant* and the *buying market participant* in accordance with **MR Ch.8 s.2.1.3.4** and **MR Ch.9 s.3.10**.

Each *hourly uplift* component (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* support data files as record type 'B'. Detailed information is provided in the document Format Specifications for Settlement Statement Files and Data Files document located on the Technical Interfaces webpage under 'Commercial Reconciliation'.

The *hourly uplift* components that may be allocated are included in Table 2-13.

Table 2-13: Allocation of Hourly Uplift Components

Hourly Uplift Component Group	Associated Charge Types	Comments
Operating Reserve Settlement Credit (ORSC)	250 252 254	Separate *charge types* for recovery of HORSA *settlement amounts* paid to *market participants* for each class of *operating reserve.*
Intertie Failure Charge Rebate (IFCR)	186	Aggregation of the following *charge types*: • *charge type* 1828 Day-Ahead Market Import Failure Charge • *charge type* 1829 Day-Ahead Market Export Failure Charge • *charge type* 1928 Real-Time Import Failure Charge • *charge type* 1929 Real-Time Export Failure Charge
Intertie Offer Guarantee Settlement Credit (IOGSC)	1977	Recovery of *charge type* 1927 Real-Time Intertie Offer *settlement amount* paid to *market participants.*
Operating Reserve Shortfall Settlement Debit (ORSSD)	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.*
Generator Failure Charge Rebate (GFCR)	1970	Distribution of *charge type* 1920 Generator Failure Charge – Market Price Component received from *market participants.*

Hourly Uplift Component Group	Associated Charge Types	Comments
Day-Ahead Market Settlement Credit (DAMSC)	1865	Aggregation of the following *charge types*: • *charge type* 1815 Day-Ahead Market Balancing Credit – Energy • *charge type* 1816 Day-Ahead Market Balancing Credit – Operating Reserve
Real-Time Market Settlement Credit (RTMSC)	1950	Aggregation of the following *charge types*: • *charge types* 1900 to 1907 for Real-Time Make-Whole Payment *settlement amounts*

2.4.3.1   Reallocate Quantity

The effect of selecting an *hourly uplift* component group within the *physical bilateral contract data,* is the creation of a "Reallocate Quantity (RQ)".

The RQ is:

- specific to a single *physical bilateral contract* and is exactly equal to the quantity of *energy* involved in the *physical bilateral contract* itself;

- specific to a single *market participant* and 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*;

- specific to a single *market participant* for a particular *hourly uplift* component group and is equal to the sum of all RQ quantities designated to for that particular *hourly uplift* component group within the *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*.

- applied to the calculation of the *settlement amounts* for each *charge type* associated with the *hourly uplift* component group as per Table 2-4.

Therefore, when calculating the RQ quantity for a particular *hourly uplift charge type* for *market participant* 'k' at a *delivery point* 'm' and *intertie metering point* 'i' in *metering interval* 't' of *settlement hour* 'h', the reallocate quantity is expressed according to the **MR Ch.9 Appendix 9.2 s.6.1.9**:

$$RQ_{k,h}^{m,i,t} = \left[\sum_{B} \frac{DAM\_BCQ_{k,b,h}^{m,i}}{12} - \sum_{S} \frac{DAM\_BCQ_{s,k,h}^{m,i}}{12} + \sum_{B} BCQ_{k,b,h}^{m,i,t} - \sum_{S} BCQ_{s,k,h}^{m,i,t} \right]$$

The RQ quantity is then used to either increase or decrease the *settlement amount* for the *hourly uplift charge type* 'c' in accordance with **MR Ch.9 s.3.10** as follows:

$$HUSA_{k,h} = HUSA_h \; x \left[\sum_{}^{M,T} \left(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t} + RQ_{k,h}^{m,i,t} \right) / \sum_{K}^{M,T} \left(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t} \right) \right]$$

Note:

In the event that the term $\left(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t} + RQ_{k,h}^{m,i,t} \right) < 0$

Where:

$$RQ_{k,h}^{m,i,t} < 0 \; and \; \left| RQ_{k,h}^{m,i,t} \right| > \left| \left(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t} \right) \right| and \; TD_{k,h,c} > 0$$

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 2.4.3. Refer to section 2.2 for specific listings of *charge types* and their respective equations.

-   **End of Section -**

3.   Inactive IESO Charge Types and Equations

The provisions of this section are applicable to those *IESO charge types* and equations that are no longer active, as further described in [section 1.2](#), and have been retained in the event that a re-calculation of the *charge type* is required.

All *market rule* and *market manual* references, in this section, are to those *market rules* and *market manuals* that were in effect prior to the commencement of *market transition*, unless otherwise stated.

3.1.   Variable Descriptions

The following Table 3-1 contains descriptions of variables used within [section 3.2.](#) Variables not defined in this table are as defined in section 2.1.

Table 3-1: Variable Descriptions for Inactive Charge Types and Equations

Key to the Table Below				
Variable used within Section 3	**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*.
$CAEO^m_{h,k}$	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*
$CBMP_k$	Total net volume of electricity withdrawn from the *IESO-controlled grid* by applicable Class B market participant or licensed	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	N/A	N/A – Refer to regulations.

		Key to the Table Below		
Variable used within Section 3	**Data Description**	**Description**	**Market Rules Reference**	**Relation to the corresponding variable description within the IESO Market Rules**
	distributor that is also a *market participant* for the month	licensed distributor that is a *market participant* 'k' for the month.		
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 – Refer to regulations.
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*). 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*).	9.4.7B	Same as *IESO market rules*.
DA_BE$_{k,h}^{m,t}$	*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*.
DA_BE$_{k,h}^{i,t}$	*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 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.	9.3.8A.2B and 9.3.8B.2	Same as *IESO market rules*
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*

		Key to the Table Below		
Variable used within Section 3	**Data Description**	**Description**	**Market Rules Reference**	**Relation to the corresponding variable description within the 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 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).	9.4.7D.1	Same as *IESO market rules*
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 metering point* in the import zone	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'.	9.3.1.2A	Same as *IESO market rules*.
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*.

		Key to the Table Below		
Variable used within Section 3	**Data Description**	**Description**	**Market Rules Reference**	**Relation to the corresponding variable description within the 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 *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.	9.3.1.11	Same as *IESO market rules*. Refer to Market Manual 9.5, Appendix B for a detailed description of DIPC.
$DIGQ_{k,h}{}^{m,t}$	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).

		Key to the Table Below		
Variable used within Section 3	**Data Description**	**Description**	**Market Rules Reference**	**Relation to the corresponding variable description within the IESO Market Rules**
$DQSW_{k,h}{}^{m,t}$	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).
$DRACP$	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
$DREBQ^m{}_{k,h}$	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 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	9.3.1.10	Same as *IESO market rules*

		Key to the Table Below		
Variable used within Section 3	**Data Description**	**Description**	**Market Rules Reference**	**Relation to the corresponding variable description within the IESO Market Rules**
		$\mathrm{CARC}_k{}^m$ for the resource in the relevant *energy market billing,* the $\mathrm{DREBQ}^m{}_{k,h}$ shall equal such $\mathrm{CARC}_k{}^m$		
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
$\mathrm{EIM}_{k,h}$	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	$\mathrm{EIM}_{k,h}$ IS NOT A VARIABLE $\mathrm{EIM}_{k,h}$ is the output of a particular usage of the Operating Profit (OP) function defined within Chapter 9, section 3.8A. $\mathrm{EIM}_{k,h}$ Input variables into the Operating Profit (OP) Function include: MQSI, EMP, and BE.
$\mathrm{EMP}_h{}^{i,t}$	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.*
$\mathrm{EMP}_h{}^{m,t}$	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.*
$\mathrm{EMP}_h{}^{REF,t}$	5-minute Energy Market Reference Price	Reference energy *market price* used to value losses in the calculation of the *Transmission Charge Reduction Fund*[8] during in *metering interval* 't' of *settlement hour* 'h'.	9.3.1.3 and 9.3.6.2	Same as *IESO market rules.*
$\mathrm{FP}_h{}^m$	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	N/A – Refer to regulations.

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[3] *Market Rules* ref.: Section 3.6.2 of Chapter 9.

		Key to the Table Below		
Variable used within Section 3	**Data Description**	**Description**	**Market Rules Reference**	**Relation to the corresponding variable description within the IESO Market Rules**
			commencing April 1, 2005.	
$FPC_h{}^m$	Rate for a designated group of *charge types* (refer to 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. Refer to Ontario Regulation 436/02 and Ontario Regulation 98/05.	N/A – subject to regulations made pursuant to *Ontario Energy Board Act, 1998*.	N/A – Refer to regulations
$HOEP_h$	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 *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 (refer to also, section 2.2 entry for *charge type* 1137 within this document).
			9.3.8A.8	Same as *IESO market rules*
				
				Refer to Chapter 9, section 3.8A.8 for details concerning its formulation.

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 – Refer to regulations.
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	N/A	N/A – Refer to regulations.

	Key to the Table Below			
Variable used within Section 3	**Data Description**	**Description**	**Market Rules Reference**	**Relation to the corresponding variable description within the IESO Market Rules**
		allocated to Class B customers that was deferred in April, May and June of 2020.		
$MC_h{}^m$	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'. Refer to 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 maintain without ignition support in *metering interval* 't' of *settlement hour* 'h'.	9.3.1.2B.7	Same as *IESO market rules*.
$MLP\_CONS_{k,h}{}^{m,t}$	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	9.3.8A.4	Same as *IESO market rules*.

Key to the Table Below				
Variable used within Section 3	**Data Description**	**Description**	**Market Rules Reference**	**Relation to the corresponding variable description within the IESO Market Rules**
		settlement hour 'h' corresponding with each quantity, MQSIx*,k,h i,t in matrix MI, row x*.		
$MQSW_{k,h}{}^{m,t}$	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*.
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 x (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).
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

Key to the Table Below				
Variable used within Section 3	**Data Description**	**Description**	**Market Rules Reference**	**Relation to the corresponding variable description within the IESO Market Rules**
				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 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	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 refer to the *market rules* for information regarding its formulation.

		Key to the Table Below		
Variable used within Section 3	**Data Description**	**Description**	**Market Rules Reference**	**Relation to the corresponding variable description within the IESO Market Rules**
		schedule is the lesser of $PDR\_DQSI_{k,h}{}^{i,t}$ or $DQSI_{k,h}{}^{i,t}$ 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).
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).
$PD\_BE_{k,h}{}^{i,t}$	*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*	9.3.1.2D	Same as *IESO market rules.*

		Key to the Table Below		
Variable used within Section 3	**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.		
$PD\_DQSI_{k,h}^{i,t}$	*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*.
$PDR\_BE_{k,h}^{i,t}$	*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.	9.3.1.2A	Same as *IESO market rules*

Variable used within Section 3	Data Description	Description	Market Rules Reference	Relation to the corresponding variable description within the IESO Market Rules
		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'.		
$PDR\_DQSI_{k,h}{}^{m,t}$	*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*
$RPPVA_k$	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 – Refer to regulations.
$SQROR_{r,k,h}{}^{m,t}$	Scheduled Quantity of cl3ass 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*.
$X_h{}^{m,t}$	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*

3.2. Charge Types and Equations

The following Table 3-2 contains all inactive *charge types.* For a description of each column heading, refer to Table 2-1.

3.2.1. Inactive – Physical Market Charge Types and Equations

Table 3-2: Inactive Charge Types and Equations in the Physical Market

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
100	Net Energy Market Settlement for Generators and Dispatchable Load	$NEMSC_{k,h}$	9.3.3.2	**CALCULATIONS FOR *CHARGE TYPE* 100 END APRIL 30, 2023** 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* $$\sum_{t,m} (EMP_h^{m,t} \times ((AQEI_{k,h}^{m,t} + SQEI_h^i - AQEW_{k,h}^{m,t} - SQEW_h^i) + \sum_{s,b} (BCQ_{s,k,h}^{m,t} - BCQ_{k,b,h}^{m,t})))$$ For an *intertie metering point* associated with a withdrawing *boundary entity* where that *intertie congestion price* is not less than zero: $$\sum_{t,m} ((MAX (X_h^{m,t}, EMP_h^{m,t}) \times AQEI_{k,h}^{m,t}$$	Interval	Either Way	13	13	0	13	

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
101	Net Energy Market Settlement for Non-dispatchable Load	$NEMSC_{k,h}$	9.3	**CALCULATIONS FOR *CHARGE TYPE* 101 END APRIL 30, 2023** $HOEP_h \times \sum_{t,m} (AQEI_{k,h}^{m,t} - AQEW_{k,h}^{m,t} + \sum_s BCQ_{s,k,h}^{m,t}) - \sum_{n,b,t} (EMP_h^{m,t} \times BCQ_{k,b,h}^{n,t})$	Hourly	Either Way	13	N/A	N/A	N/A	
103 MRP retired	Transmission Charge Reduction Fund	$TCRF_h$	9.3.6.2 And 8.4.18	$\sum_{t,m} (EMP_h^{m,t} - EMP_h^{REF,t}) \times \sum_k (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t} - AQEI_{k,h}^{m,t} - SQEI_{k,h}^{i,t}) - \sum_k TRSC_{k,h}$	Hourly	Accumulates in the *TR Clearing Account*	N/A	N/A	N/A	N/A	Refer to *IESO market rules*, Chapter 8 section 4.18 for further details.
104 MRP updated	Transmission Rights Settlement Credit	$TRSC_{k,h}$	9.3.6.1	**The following was effective prior to the commencement of *market transition*. Refer to section 2 for version in effect on the commencement of *market transition*.** $MAX((0), (\sum_{j,i} 1/12 \times QTR_{k,h}^{i,j} \times \sum_t (EMP_h^{j,t} - EMP_h^{i,t}))$	Hourly	Due MP	0	0	0	0	
105 MRP retired	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). $AQEI_{k,h}^{m,t}$ and $EMP_h^{m,t}$ may be	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

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
				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 $-1OP(EMP_h{}^{m,t}, MQSW_{k,h}{}^{m,t}, BL) - MAX(-1OP(EMP_h{}^{m,t}, DQSW_{k,h}{}^{m,t}, BL), -1OP(EMP_h{}^{m,t}, AQEW_{k,h}{}^{m,t}, BL))$ 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 constrained schedule for the same dispatch interval as a result of the *market participant*'s offers being partially or fully uneconomic: $OPE(EMP_h{}^{m,t}, MQSI_{k,h}{}^{m,t}, BE) - OP(EMP_h{}^{m,t}, AQEI_{k,h}{}^{m,t}, BE)$ Refer to 9.3.5.2 for the definition of the Operating Profit (OP) function referenced above.							*dispatch data* provided by that *market participant*. Offer prices in matrix 'BE' may be revised down to a lower limit as described in 9.3.5.6. Refer to 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.
106 MRP retired	Congestion Management Settlement Credit for 10 Minute	$CMSC_{r,k,h}$	9.3.5.2	$OP(PROR_{r,h}{}^{m,t}, SQROR_{r,k,h}{}^{m,t}, BR_r) - MAX(OP(PROR_{r,h}{}^{m,t}, DQSR_{r,k,h}{}^{m,t}, BR_r), OP(PROR_{r,h}{}^{m,t}, AQOR_{r,k,h}{}^{m,t}, BR_r))$	Interval	Either Way	13	N/A	N/A	N/A	This *charge type* holds the *market participant* to the expected

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
	Spinning Reserve			Refer to 9.3.5.2 for the definition of the Operating Profit (OP) function referenced above.							profits implied by the *market schedule* derived on *dispatch data* provided by that *market participant*.
107 MRP retired	Congestion Management Settlement Credit for 10 Minute Non-spinning Reserve	$CMSC_{r,k,h}$	9.3.5.2	$OP(PROR_{r,h}^{m,t}, SQROR_{r,k,h}^{m,t}, BR_r) - MAX(OP(PROR_{r,h}^{m,t}, DQSR_{r,k,h}^{m,t}, BR_r), OP(PROR_{r,h}^{m,t}, AQOR_{r,k,h}^{m,t}, BR_r))$ Refer to 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*.
108 MRP retired	Congestion Management Settlement Credit for 30 Minute Operating Reserve	$CMSC_{r,k,h}$	9.3.5.2	$OP(PROR_{r,h}^{m,t}, SQROR_{r,k,h}^{m,t}, BR_r) - MAX(OP(PROR_{r,h}^{m,t}, DQSR_{r,k,h}^{m,t}, BR_r), OP(PROR_{r,h}^{m,t}, AQOR_{r,k,h}^{m,t}, BR_r))$ Refer to 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*.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
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* 'H'. 'AQEW' is limited to a maximum of 1,000,000 MWh annually per eligible *market participant*.	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.
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 MRP retired	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

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
120 MRP retired	Local Market Power Debit	9.4.8.2.2 And Ch. 7, Appendix 7.6		Manual Entry as per 9.4.8.2.2	Monthly	Due *IESO*	13	13	0	13	
121	Northern Industrial Electricity Rate Program Settlement Amount	N/A	N/A	**** PROGRAM END APRIL 30, 2022 AND REPLACED BY NORTHERN ENERGY ADVANTAGE PROGRAM SETTLEMENT AMOUNT UNDER THE SAME CHARGE TYPE **** $= \sum_M \sum_H^T (AQEW_{mh}^t) \times (Rate)$ 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	Eligibility, rates, and other implementation details subject to Ministry of Northern Development, Mines, Natural Resources and Forestry specifications.
122 MRP retired	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 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 $Q_{s*} \le Q \le Q_n$ and where, $Q_0=0$ Using the terms below, let RDC$_{k,h}^{m,t}$ be expressed as follows:	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	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 (%)	Comments
				$RDC_{k,h}^{m,t} = MAX[0, [OP(EMP_h^{m,t}, MQSI_{k,h}^{m,t}, BE) - MAX(OP(EMP_h^{m,t}, DQSI_{k,h}^{m,t}, BE), OP(EMP_h^{m,t}, AQEI_{k,h}^{m,t}, BE))]]$ $RDSA_{k,h}^{m,t} = MIN(-1 \times RDCB_{k,h}^{m,t}, RDC_{k,h}^{m,t})$							
124 MRP retired	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 $IOG_{k,h}OFFSET$	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 *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: $\sum_I (-1)MIN[0, \sum^T OP(EMP_h^{i,t}, MQSI_{k,h}^{i,t}, BE)]$ Refer to 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: $= DA\_IOG_{k,h} + EIM_{k,h} - \sum^I (-1) * MIN[0, \sum^T OP(EMP_h^{i,t}, QSI\{adj\}_{k,h}^{i,t}, BE_{k,h}^{i,t}$ or $PDR\_BE_{k,h}^{i,t}) + \sum^T QSI\{adj\}_{k,h}^{i,t} / \sum^T MI_{k,h}^t[n,1] * OPE'_{k,h}^i]$	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 *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

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
				(Refer to 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).							section 3.5.8.1 of Chapter 7.
133 MRP retired	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* (refer to 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: - the end of *minimum generation block run-time;* or - the end of the unit's *minimum 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 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). $RT\_COST_k = \sum^{T*}{}_{H1} COST(AQEI\{limited\}_{k,h}{}^{m,t}, BE)$							

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
				A. Where the COST function is defined as follows: $$\text{COST}(Q,\,B) = \sum_{i=1}^{s^*} P_i \cdot (Q_i - Q_{i-1})$$ where: • B is the n x 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' 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:							

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments

				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 $CMSC\_REV_{k,h}^{m,t} = OP(EMP_h^{m,t}, MLP, BE) - OP(EMP, max(DQSI_{k,h}^{m,t}, AQEI_{k,h}^{m,t}), BE)$.
				 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 $CMSC\_REV_{k,h}^{m,t} = OP(EMP_h^{m,t}, MQSI_{k,h}^{m,t}, BE) - OP(EMP_h^{m,t}, MLP, BE)$
				
				 (Refer to applicable *market manual*)							

134 MRP retired	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 MRP retired	Real-time Import Failure Charge	$RT\_IFC_{k,h}$	9.3.8C.3	$\sum^{I,T} (-1) * MIN[MAX[0, (EMP_h^{m,t} + PB\_IM_h^t - PD\_EMP_h^{m,t}) * RT\_ISD_{k,h}^{i,t}], (MAX(0, EMP_h^{m,t}) * RT\_ISD_{k,h}^{i,t})]$ Where: 'I' is the set of all *intertie metering points* 'i'.	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	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 (%)	Comments
				'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 MRP retired	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 MRP retired	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 Guarantee Program, section 5.4 Fuel Cost Recovery Methodology.	Monthly	Due MP	13	N/A	N/A	N/A	
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:**	Hourly (type 'DP' records only. Refer to [Format Specifications 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	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 (%)	Comments
				$\Sigma_{T,m}\,(EMP_h^{m,t} - FP_h{}^m) \times (AQEW_{k,h}{}^{m,t} - AQEI_{k,h}{}^{m,t} - \Sigma_s\,BCQ_{s,k,h}{}^{m,t})$ **Where net uncovered consumption = 0:** $\Sigma_{T,m}\,(EMP_h^{m,t} - FP_h{}^m) \times (-AQEI_{k,h}{}^{m,t})$ **SUBJECT TO:** Net uncovered consumption = MAX $[\Sigma_{T,m}\,(AQEW_{k,h}{}^{m,t} - \Sigma_s\,BCQ_{s,k,h}{}^{m,t}), 0]$ **Fixed Energy Rate Settlement Amount (non-dispatchable locations):** **Where net uncovered consumption > 0:** $(HOEP_h - FP_h{}^m) \times \Sigma_{m,T}\,(AQEW_{k,h}{}^{m,t} - AQEI_{k,h}{}^{m,t} - \Sigma_s\,BCQ_{s,k,h}{}^{m,t})$ **Where net uncovered consumption = 0:** $(HOEP_h - FP_h{}^m) \times \Sigma_{m,T}\,(-AQEI_{k,h}{}^{m,t})$ **SUBJECT TO:** Net uncovered consumption = MAX $[\Sigma_{T,m}\,(AQEW_{k,h}{}^{m,t} - \Sigma_s\,BCQ_{s,k,h}{}^{m,t}), 0]$ **SUBJECT TO:** Net uncovered consumption = MAX $[\Sigma_{T,m}\,(AQEW_{k,h}{}^{m,t} - \Sigma_s\,BCQ_{s,k,h}{}^{m,t}), 0]$							
141	Fixed Wholesale Charge Rate Settlement Amount	N/A	N/A	**** CALCULATIONS FOR *CHARGE TYPE* 141 END MARCH 31, 2005 **** **NOTE:** 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. Refer to IMO_FORM_1562 for further details. $TD_{k,c} - \Sigma_{M,H}\,AQEW_{k,h}{}^{m,t} * (FPC)$	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	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 (%)	Comments
				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**							
146	Global Adjustment Settlement Amount	N/A	N/A	****CALCULATIONS FOR *CHARGE TYPE* 146 END DECEMBER 31, 2010. *CHARGE TYPE* 146 REPLACED BY *CHARGE TYPES* 147 AND 148 EFFECTIVE JANUARY 1, 2011.**** For Fort Frances Power Corporation Distribution Inc.: $\Sigma_{H,M,C} TD \times$ $(\Sigma_{H}{}^{M,T} AQEW_{k,h}{}^{m,t} + EGEI_k - EEQ) / (\Sigma_{K,H}{}^{M,T} AQEW_{k,h}{}^{m,t} + \Sigma_K EGEI_k - EEQ)$ For other market participants: $\Sigma_{H,M,C} TD \times$ $(\Sigma_{H}{}^{M,T} AQEW_{k,h}{}^{m,t} + EGEI_k) / (\Sigma_{K,H}{}^{M,T} AQEW_{k,h}{}^{m,t} + \Sigma_K EGEI_k - EEQ)$ 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 'C' is the set of the following charge types 'c':	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	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 (%)	Comments
				193, 194, 195, 197, 198, 1380, 1381, 1382, 1383, 1384, 1385, 1386, 1390, 1391, 1392, 1393, 1394, 1395, 1396, 1397, 1398, 1450, 1460, 1462 and 1464.							
150 MRP retired	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: **1101, 1103, 1111, 1113, 1114, 1115, 103, 104, 1131** '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: $RQ_{k,h}{}^{m,t} = \sum_{s,b} [BCQ_{k,b,h}{}^{m,t} - BCQ_{s,k,h}{}^{m,t}]$	Hourly	Either Way	13	N/A	0	13	
155 MRP retired	Congestion Management Settlement Uplift	N/A	9.3.5.2 and 9.3.5.7	$\sum_c{}^{M,T} TD_{k,h,(105, 106, 107, 108, 122, 124, 1050, 1051)} \times [(AQEW_{k,h}{}^{m,t} + SQEW_{k,h}{}^{i,t} + RQ_{k,h}{}^{m,t}) / \sum_k{}^{M,T} (AQEW_{k,h}{}^{m,t} + SQEW_{k,h}{}^{i,t})]$ 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 CMSC 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 or Monthly (refer to 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.
161	Northern Pulp and Paper Mill Electricity	N/A	N/A	$\sum_K TD_{k,111}$	Quarterly	Due *IESO*	0	N/A	N/A	N/A	This program ends on

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
	Transition Program Balancing Amount			Where 'k' is part of a subset of eligible *market participants* 'k'.							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) x (ONPAO$_h$ x 0.85 − PAA) + (PAP − PAORL) x PAA)] OPG rebate (n) = Max [0, Payment (n) − Payment (n-1) + NCF (n-1)] Where: '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)]	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 made to OPG and any such amount will be carried forward into subsequent quarters.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
163 MRP retired	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.
170 MRP retired	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	$= \sum_{H,C}^{M,T} TD_c \times [(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}) / \sum_{k,H}^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t})]$ Where '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	**** PROGRAM END APRIL 30, 2022 AND REPLACED BY NORTHERN ENERGY ADVANTAGE PROGRAM BALANCING AMOUNT UNDER THE SAME CHARGE TYPE **** $\sum_K TD_{k,121}$ Where 'k' is part of a subset of eligible *market participants* 'k'.	Quarterly	Due *IESO*	0	N/A	N/A	N/A	
183 MRP retired	Generation Cost Guarantee Recovery Debit	N/A	9.4.8.1.9	$= \sum_{H,C}^{M,T} TD_{h,c} \times [(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}) / \sum_{k,H}^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t})]$ Where: 'C' is the set of the following *charge types* 'c' as follows: **133, 137**	Monthly	Due *IESO*	13	N/A	0	13	

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
				'H' is the set of all *settlement hours* 'h' in the month. '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*.
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. Refer to: [Format Specifications 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.
198	Renewable Generation Balancing Amount	N/A	N/A	** **CALCULATIONS FOR *CHARGE TYPE* 198 END DECEMBER 31, 2010. ** $\sum_{K} TD_{k,148}$	Pending	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	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 (%)	Comments
				Where 'K' is the set of all *market participants* 'k'. Where $TD_{k,148}$ is the *settlement amount* of *charge type* 148 for the month for *market participant* 'k'.							
200 MRP retired	10 Minute 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	
202 MRP retired	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	
204 MRP retired	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	
206 MRP updated	10-Minute spinning non-Accessibility Settlement Amount	$ORSCB_{r,k,h}$	9.3.4.2-9.3.4.3	****The following was effective prior to the commencement of *market transition*. Refer to section 2 for version in effect on the commencement of *market transition*.**** **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* *or,* $MAX(0,MAX\_CAP_{k,h}{}^{m,t} - AQEI_{k,h}{}^{m,t})$ for *generators*	Interval	Due *IESO*	13	N/A	N/A	N/A	Please refer to MR-00467

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
				For aggregated generators: $$ORIA\_CA_{r1,k,h}{}^{M,t} \times ORCF_{r1,k,h}{}^{m,t} \times PROR_{r1,h}{}^{m,t}$$ Where: $$ORIA\_CA_{r1,k,h}{}^{M,t} = MIN(0, TAOR\_CA_{k,h}{}^{M,t} - \textstyle\sum_M AQOR_{r1,k,h}{}^{m,t})$$ $$TAOR\_CA_{k,h}{}^{M,t} =$$ $$MAX(0, \textstyle\sum_M (MAX\_CAP_{k,h}{}^{m,t} - AQEI_{k,h}{}^{m,t}))$$ $$ORCF_{r1,k,h}{}^{m,t} = ORIA_{r1,k,h}{}^{m,t} / (\textstyle\sum_{M1} ORIA_{r1,k,h}{}^{m,t}),$$ and M1 represents the set of all delivery points 'm' offering 10-minute synchronized OR $$ORIA_{r1,k,h}{}^{m,t} = MIN(0, (TAOR_{k,h}{}^{m,t} - AQOR_{r1,k,h}{}^{m,t}))$$							
208 MRP updated	10-Minute non-Spinning non-Accessibility Settlement Amount	$ORSCB_{r,k,h}$	9.3.4.2-9.3.4.3	****The following was effective prior to the commencement of *market transition*. Refer to section 2 for version in effect on the commencement of *market transition*.**** **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:** $$ORIA\_CA_{r2,k,h}{}^{M,t} \times ORCF_{r2,k,h}{}^{m,t} \times PROR_{r2,h}{}^{m,t}$$	Interval	Due *IESO*	13	N/A	N/A	N/A	Please refer to MR-00467

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
				Where: $$ORIA\_CA_{r2,k,h}^{M,t} = MIN(0,TAOR\_CA_{k,h}^{M,t} - \sum_M AQOR_{r2,k,h}^{m,t})$$ $$TAOR\_CA_{k,h}^{M,t} =$$ $$MAX(0,\sum_M (MAX\_CAP_{k,h}^{m,t} - AQEI_{k,h}^{m,t}))$$ $$ORCF_{r2,k,h}^{m,t} = ORIA_{r2,k,h}^{m,t} / (\sum_{M2} ORIA_{r2,k,h}^{m,t})$$, 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 MRP updated	30-Minute non-Accessibility Settlement Amount	$ORSCB_{r,k,h}$	9.3.4.2-9.3.4.3	****The following was effective prior to the commencement of** *market transition*. **Refer to section 2 for version in effect on the commencement of** *market transition*.****** **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*: $$ORIA\_CA_{r3,k,h}^{M,t} \times ORCF_{r3,k,h}^{m,t} \times PROR_{r3,h}^{m,t}$$ Where:	Interval	Due *IESO*	13	N/A	N/A	N/A	Please refer to MR-00467

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
				$ORIA\_CA_{r3,k,h}{}^{M,t} = MIN(0,TAOR\_CA_{k,h}{}^{M,t} - \sum_M AQOR_{r3,k,h}{}^{m,t})$ $TAOR\_CA_{k,h}{}^{M,t} =$ $MAX(0,\sum_M (MAX\_CAP_{k,h}{}^{m,t} - AQEI_{k,h}{}^{m,t}))$ $ORCF_{r3,k,h}{}^{m,t} = ORIA_{r3,k,h}{}^{m,t} / (\sum_{M3} ORIA_{r3,k,h}{}^{m,t})$, and M3 represents the set of all delivery points 'm' offering 30-minute OR $ORIA_{r3,k,h}{}^{m,t} = MIN(0,(TAOR_{k,h}{}^{m,t} - AQOR_{r3,k,h}{}^{m,t}))$							
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*.
702	Debt Retirement Credit	N/A	9.4.6	**** CALCULATIONS FOR *CHARGE TYPE* 702 END MARCH 31, 2018 **** $\sum_{k,H,c} TD_{752}$	Monthly	Due Ministry of Finance	0	N/A	N/A	N/A	Ontario Regulations 493/01 and 494/01 Refer to Ministry of Energy website for details.
704	OPA Administration Credit	N/A	N/A	**** CALCULATIONS FOR *CHARGE TYPE* 704 END DECEMBER 31, 2016 **** $\sum_K TD_{k,754}$ Where 'K' is the set of all *market participants* 'k'. Where $TD_{k,754}$ 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.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
752	Debt Retirement Charge	N/A	9.4.6	** **CALCULATIONS FOR *CHARGE TYPE* 702 END MARCH 31, 2018** ** $AQEW_{k,h}{}^{m,t} \times TP$ 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 Refer to Ministry of Energy website for details.
754	OPA Administration Charge	N/A	N/A	** **CALCULATIONS FOR *CHARGE TYPE* 704 END DECEMBER 31, 2016** ** $\sum_H{}^T AQEW_{k,h}{}^{m,t} \times TP$ Where 'H' is the set of all *settlement hours* 'h' in the month. Where 'T' is the set of all *metering intervals* 't' in *settlement hour* 'h'. Where TP is the rate ($/MWh) for the *OPA* Administration Charge set by *OEB*.	Monthly	Due *IESO*	13	N/A	N/A	N/A	Eligibility, rates, and other implementation details subject to government regulation.
1050 MRP retired	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 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	Interval	Due *IESO*	13	N/A	N/A	N/A	The decision rule for ramping up or down is described in 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	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 (%)	Comments
				than or equal to MMCP, indicating that it is a non-dispatchable in that range. $[-1OP(EMP_h{}^{m,t}, MQSW_{k,h}{}^{m,t}, BL) - MAX(-1OP(EMP_h{}^{m,t}, DQSW_{k,h}{}^{m,t}, BL), -1 OP(EMP_h{}^{m,t}, AQEW_{k,h}{}^{m,t}, BL)] -$ $[-1OP(EMP_h{}^{m,t}, MQSW_{k,h}{}^{m,t}, BL) - MAX(-1OP(EMP_h{}^{m,t}, DQSW_{k,h}{}^{m,t}, BL), -1OP(EMP_h{}^{m,t}, AQEW_{k,h}{}^{m,t}, BL), -1OP(EMP_h{}^{m,t}, MC_h{}^{m}, BL)]$ 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: • 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							

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
				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: • 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 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 *operating reserve* if one or more of the following conditions exist: a. The constrained schedule is labeled with the reason code 'ORA'.							

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
				b. The interval is 1-3 intervals before an interval with the 'ORA' code. c. 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: a. It is one of the first 3 intervals of the second hour when ramping up. b. 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 constrain off the load for system or for local requirements.							
1051 MRP retired	Ramp-Down CMSC Claw Back	$RDCB_{k,h}$	9.3.5.1G	$$RDCB_{k,h}{}^{m,t} = -1 \times TD_{k,h,105}{}^{m,t}$$ (Refer to 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 MRP updated + name change	Real-Time Energy Settlement Amount for Dispatchable Generators	$NEMSC_{k,h}$	9.3.3.2	****The following was effective prior to the commencement of *market transition*. Refer to section 2 for version in effect on the commencement of *market transition*.**** $$EMP_h{}^{m,t} \times ((AQEI_{k,h}{}^{m,t} - AQEW_{k,h}{}^{m,t}) + \Sigma_{S,B} (BCQ_{s,k,h}{}^{m,t} - BCQ_{k,b,h}{}^{m,t}))$$	Interval	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	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 (%)	Comments
1103 MRP updated	Real-Time Energy Settlement Amount for Dispatchable Loads	$NEMSC_{k,h}$	9.3.3.2	**The following was effective prior to the commencement of *market transition*. Refer to section 2 for version in effect on the commencement of *market transition*.** $EMP_h^{m,t} \times ((AQEI_{k,h}^{m,t} - AQEW_{k,h}^{m,t}) + \Sigma_{S,B} (BCQ_{s,k,h}^{m,t} - BCQ_{k,b,h}^{m,t}))$	Interval	Either Way	13	N/A	N/A	N/A	
1111 MRP updated	Real-Time Energy Settlement Amount for Imports	$NEMSC_{k,h}$	9.3.3.2	**The following was effective prior to the commencement of *market transition*. Refer to section 2 for version in effect on the commencement of *market transition*.** $EMP_h^{i,t} \times (SQEI_{k,h}^{i,t} + \Sigma_{S,B} (BCQ_{s,k,h}^{m,t} - BCQ_{k,b,h}^{m,t}))$	Interval	Either Way	N/A	13	N/A	N/A	
1113 MRP updated	Real-Time Energy Settlement Amount for Exports	$NEMSC_{k,h}$	9.3.3.2	**The following was effective prior to the commencement of *market transition*. Refer to section 2 for version in effect on the commencement of *market transition*.** $EMP_h^{i,t} \times (((-1) \times SQEW_{k,h}^{i,t}) + \Sigma_{S,B} (BCQ_{s,k,h}^{m,t} - BCQ_{k,b,h}^{m,t}))$	Interval	Either Way	N/A	N/A	0	13	
1114 MRP retired	Real-Time Energy Settlement Amount for Non-Dispatchable Generators	$NEMSC_{k,h}$	9.3	$(HOEP_h \times \Sigma_T(AQEI_{k,h}^{m,t} - AQEW_{k,h}^{m,t} + \Sigma_S(BCQ_{s,k,h}^{m,t}))) - (\Sigma_{B,T} (EMP_h^{m,t} \times BCQ_{b,k,h}^{m,t}))$	Hourly	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	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 (%)	Comments
1115 MRP updated + name change	Real-Time Energy Settlement Amount for Non-Dispatchable Loads	$NEMSC_{k,h}$	9.3	**The following was effective prior to the commencement of *market transition*. Refer to section 2 for version in effect on the commencement of *market transition*.** $(HOEP_h \times \Sigma_T(AQEI_{k,h}^{m,t} - AQEW_{k,h}^{m,t} + \Sigma_S(BCQ_{s,k,h}^{m,t}))) - (\Sigma_{B,T}(EMP_h^{m,t} \times BCQ_{b,k,h}^{m,t}))$	Hourly	Either Way	13	N/A	N/A	N/A	
1130	Day-Ahead Intertie Offer Guarantee Settlement Credit	$DA\_IOG_{k,h}$	9.3.8A.2A	**CALCULATIONS FOR *CHARGE TYPE* 1130 END OCTOBER 12, 2011. *CHARGE TYPE* 1130 REPLACED BY *CHARGE TYPE* 1131 EFFECTIVE OCTOBER 13, 2011.** 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*: $\Sigma^I (-1) * MIN[0, \Sigma^T OP(EMP_h^{i,t}, MIN(PDR\_DQSI_{k,h}^{i,t}, DQSI_{k,h}^{i,t}), PDR\_BE_{k,h}^{i,t}) + TD_{k,h,105}^i]$ Or, in the case of an import transaction subject to a *constrained on event* in the *real-time market*: $\Sigma^I (-1) * MIN[0, \Sigma^T OP(EMP_h^{i,t}, MIN(PDR\_DQSI_{k,h}^{i,t}, DQSI_{k,h}^{i,t}), PDR\_BE_{k,h}^{i,t}) + OPE\{adj\}_{k,h}^{i,t}]$ Refer to 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'.	Hourly	Due MP	N/A	13	13	13	

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
				$TD_{k,h,105}{}^{i}$ 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 MRP retired	Intertie Offer Guarantee Settlement Credit	$IOG_{k,h}$	9.3.8A	The Day-Ahead Intertie Offer Guarantee *settlement amount* is derived as follows: $$\sum_I \ MAX[0, \ \textstyle\sum^T (DA\_IOG\_COMP1 + DA\_IOG\_COMP2 - DA\_IOG\_COMP3)]$$ 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	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	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 (%)	Comments
				3. $DQSI > DA\_DQSI > MQSI$ 4. $MQSI > DA\_DQSI > DQSI$ 5. $DA\_DQSI >= DQSI > MQSI$ 6. $DA\_DQSI >= MQSI > DQSI$ Scenario 1 and 2: 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.							

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
				$XDA\_BE_{k,h}^{i,t} = (-1) * [OP(EMP_h^{i,t}, DA\_DQSI_{k,h}^{m,t}, DA\_BE) - OP(EMP_h^{i,t}, min(DA\_DQSI_{k,h}^{m,t}, DQSI_{k,h}^{m,t}, DA\_BE)]$ $XBE_{k,h}^{i,t} = (-1) * [OP(EMP_h^{i,t}, DA\_DQSI_{k,h}^{i,t}, BE) - OP(EMP_h^{i,t}, min(DA\_DQSI_{k,h}^{i,t}, DQSI_{k,h}^{i,t}, BE)]$ 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: $RT\text{-}IOG_{k,h} = EIM_{k,h}$ The Real-Time Intertie Offer Guarantee ($RT\text{-}IOG_{k,h}$) *settlement amount* is derived as follows: $\sum_I (-1)*MIN[0, \sum^T OP(EMP_h^{i,t}, MQSI_{k,h}^{i,t}, BE)]$ 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:**							

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
				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:** 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% X 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							

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
				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)]] 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	****CALCULATIONS FOR _CHARGE TYPE_ 1133 END OCTOBER 12, 2011. **** Dispatchable _delivery points:_ $MAX[0, (DA\_CGC + DA\_COST - \sum^T EMP_h^{m,t} \times AQEI\{limited\}_{k,h}^{m,t} - \sum^T CMSC REV_{k,h}^{m,t}]$ **Subject to:** $AQEI\{limited\}_{k,h}^{m,t} = MIN[AQEI_{k,h}^{m,t}, \textit{minimum loading point}]$ Where 'DA_CGC' is a Day-Ahead _Combined Guaranteed Costs_ variable, assessed in accordance with the applicable _market manual_ (refer to also section 2.1 "Variable Description").	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	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 (%)	Comments
				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). $DA\_COST_k = \sum_{H2}^{T^*} COST(AQEI\{limited\}_{k,h}^{m,t}, PDR\_BE_{k,h}^{m,t})$ 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 x 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*							

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments

				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 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
				     $CMSC\_REV_{k,h}{}^{m,t} = OP(EMP_{h}{}^{m,t}, MLP, BE) - OP(EMP, max(DQSI_{k,h}{}^{m,t}, AQEI_{k,h}{}^{m,t}), BE)$.
				
				 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
				     $CMSC\_REV_{k,h}{}^{m,t} = OP(EMP_{h}{}^{m,t}, MQSI_{k,h}{}^{m,t}, BE) - OP(EMP_{h}{}^{m,t}, MLP, BE)$
				
				 (Refer to applicable *market manual*)						

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
1134 MRP retired	Day-Ahead Linked Wheel Failure Charge	$DA\_LWFC_{k,h}$	9.3.8E	$MAX[(-1) * [(DA\_LWSD_{k,h}{}^i) * MAX[0,(DA\_PS_{k,h}{}^i - PD\_PS_{k,h}{}^i)]]$, $(RT\_IFC\_DALW_{k,h}{}^i + RT\_EFC\_DALW_{k,h}{}^i)]$ Where: $LWSD_{k,h}{}^{i,t} = MAX[MAX (DA\_DQSI_{k,h}{}^{i,t} - PD\_DQSI_{k,h}{}^{i,t}, DA\_DQSW_{k,h}{}^{i,t} - PD\_DQSW_{k,h}{}^{i,t}),0]$ $RT\_IFC\_DALW_{k,h}{}^i = \sum^{I,T} (-1) * MIN[MAX[0, (EMP_h{}^{m,t} + PB\_IM_h{}^t - PD\_EMP_h{}^{m,t}) * MAX (DA\_DQSI_{k,h}{}^{i,t} - PD\_DQSI_{k,h}{}^{i,t}, 0)], (MAX(0, EMP_h{}^{m,t})* MAX (DA\_DQSI_{k,h}{}^{i,t} - PD\_DQSI_{k,h}{}^{i,t}, 0))]$ $RT\_EFC\_DALW_{k,h}{}^i = \sum^{I,T} (-1) * MIN[MAX[0, (PD\_EMP_h{}^{m,t} - EMP_h{}^{m,t} - PB\_EX_h{}^t) * MAX (DA\_DQSW_{k,h}{}^{i,t} - PD\_DQSW_{k,h}{}^{i,t}, 0)], (MAX(0, PD\_EMP_h{}^{m,t}) * MAX (DA\_DQSW_{k,h}{}^{i,t} - PD\_DQSW_{k,h}{}^{i,t}, 0))]$ Where: 'T' is the set of 12 *metering intervals* 't' during *settlement hour* 'h'. 'I' is the set of all *intertie metering points* 'i'.	Hourly	Due *IESO*	N/A	13	13	13	

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
1135 MRP retired	Day-Ahead Import Failure Charge	$DA\_IFC_{k,h}$	9.3.8B	$\sum^{I,T}$ (-1) * MIN[MAX[0, OP($PD\_EMP_h^{m,t}$, $DA\_DQSI_{k,h}^{i,t}$, $DA\_BE_{k,k}^{i,t}$) − 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)]	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	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 (%)	Comments
1136 MRP retired	Day-Ahead Export Failure Charge	$DA\_EFC_{k,h}$	9.3.8D	$\sum^{I,T} (-1) * MIN[MAX[\ 0,(-1)*$ $OP(PD\_EMP_h{}^{m,t},\ DA\_DQSW_{k,h}{}^{i,t},\ DA\_BL_{k,k}{}^{i,t}) - (-1)*$ $OP(PD\_EMP_h{}^{m,t},\ PD\_DQSW_{k,h}{}^{i,t},\ DA\_BL_{k,k}{}^{i,t})]\ , (MAX(0,$ $XDA\_BL_{k,h}{}^{i,t} - XPD\_BL_{k,h}{}^{i,t}), (MAX(0, XDA\_BL_{k,h}{}^{i,t})]$ 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'. $XDA\_BL_{k,h}{}^{i,t} = [OP(0,DA\_DQSW,DA\_BL) - OP(0,PD\_DQSW,DA\_BL)]$ $XPD\_BL_{k,h}{}^{i,t} = [OP(0,DA\_DQSW,PD\_BL) - OP(0,PD\_DQSW,PD\_BL)]$	Hourly	Due *IESO*	N/A	N/A	0	13	
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.****	**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	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 (%)	Comments
				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*. $-1 \times TD_{k,h,c}{}^i$ 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'.						
1139	Intertie Failure Charge Reversal	IFC_REV$_{k,h}$	9.3.8C.6	****CALCULATIONS FOR *CHARGE TYPE* 1139 END OCTOBER 12, 2011.****	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	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 (%)	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 Price Plan – Final Variance Settlement Amount"; or (2) For eligible *IESO market participant consumers*: $NEMSC_{k,H} - \{ MIN [TLQ, \Sigma_H M,T (AQEW_{k,hm,t} - AQEI_{k,hm,t} - \Sigma_s BCQ_{s,k,hm,t})] \times RPPI=1 + MAX [0, \Sigma_H M,T (AQEW_{k,hm,t} - AQEI_{k,hm,t} - \Sigma_s BCQ_{s,k,hm,t}) - TLQ] \times RPPI=2 \}$	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.
1143	Ontario Fair Hydro Plan Eligible Non-RPP Consumer Discount	N/A	N/A	**REPEALED EFFECTIVE NOVEMBER 1, 2019** Manual entry based on:	Monthly	Due LDCs, Unit Sub-Meter Providers and eligible	13	N/A	N/A	N/A	

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
	Settlement Amount			(1) the values submitted via on-line settlement form "Ontario Fair Hydro Plan (OFHP) for Eligible Non-RPP Customers"		MPs either way					
1144	Ontario Fair Hydro Plan Financing Entity Amount	N/A	N/A	**REPEALED EFFECTIVE NOVEMBER 1, 2019** 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	
1145	Ontario Fair Hydro Plan Financing Entity Interest	N/A	N/A	**REPEALED EFFECTIVE NOVEMBER 1, 2019** 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	
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 ** $\Sigma_K TD_{k,1142}$ Where 'K' is the set of all *market participants* 'k'. Where $TD_{k,1142}$ 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.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
1193	Ontario Fair Hydro Plan Eligible Non-RPP Consumer Discount Balancing Amount	N/A	N/A	**REPEALED EFFECTIVE NOVEMBER 1, 2019** $\Sigma_K TD_{k,1143}$ Where 'K' is the set of all *market participants* 'k'. Where $TD_{k,1143}$ 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.
1194	Ontario Fair Hydro Plan Financing Entity Balancing Amount	N/A	N/A	**REPEALED EFFECTIVE NOVEMBER 1, 2019** $\Sigma_K TD_{k,1144}$ Where 'K' is the set of all *market participants* 'k'. Where $TD_{k,1144}$ 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	**REPEALED EFFECTIVE NOVEMBER 1, 2019** $\Sigma_K TD_{k,1145}$ Where 'K' is the set of all *market participants* 'k'. Where $TD_{k,1145}$ 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

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
1300	Capacity Based Demand Response Program Availability Payment Settlement Amount	N/A	N/A	**CALCULATIONS FOR *CHARGE TYPE* 1300 ENDED ON OCTOBER, 2018.** $= HA_H \times MCMW_h \times AAR$ 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'.	Monthly	Due MP	13	N/A	N/A	N/A	
1301	Capacity Based Demand Response Program Availability Over-Delivery Settlement Amt	N/A	N/A	**CALCULATIONS FOR *CHARGE TYPE* 1301 ENDED ON OCTOBER, 2018.** $= \sum_H (CMW_h - MCMW_h) \times AODR_h$ 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	
1302	Capacity Based Demand Response Program Availability Set-Off Settlement Amount	N/A	N/A	**CALCULATIONS FOR *CHARGE TYPE* 1302 ENDED ON OCTOBER, 2018.** The charge to a DRMP is highest of A, B or C: **A: Availability Set-Off (Reliability)**	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	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 (%)	Comments
				$= \sum_H PSO_h \times AAR \times MCMW_h$ 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)** $= PSO \times AAR \times MCMW_h \times CDP$ This formula applies when the Participant, regardless of Activation, has failed to deliver, or delivers late, a Confirmation that is required by the IESO. 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)**							

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
				$= \sum_H (PSO \times AAR \times (MCMW_h - CMW)$ 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: '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	****CALCULATIONS FOR _CHARGE TYPE_ 1303 ENDED ON OCTOBER, 2018.**** $= [\sum_H (AAM_h \times UR_h)] - [\sum_H (NG_h \times MIN(HOEP, UR_h))]$ 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. '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.	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	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 (%)	Comments
1304	Capacity Based Demand Response Program Utilization Set-Off Settlement Amount	N/A	N/A	****CALCULATIONS FOR _CHARGE TYPE_ 1304 ENDED ON OCTOBER, 2018.**** The charge to a DRMP is highest of A, B or C: **A: Utilization Set-Off (Reliability)** $= \sum_H PSO_h \times UR \times MCMW_h$ 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. '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.	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	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 (%)	Comments
				'PSO' has the same meaning as defined above. 'UR' has the same meaning as defined above. **C: Utilization Set-Off (Low Confirmation)** $= \sum_H (PSO \times UR \times (MCMW_h - CMW)$ 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	****CALCULATIONS FOR _CHARGE TYPE_ 1305 ENDED ON OCTOBER, 2018.**** 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:	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	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 (%)	Comments
				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 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. 'MCMW' has the same meaning as in CT1300. For 2.) The Activation Day Non-Performance Availability Set-Off amount is: $= (OH \times AAR \times MCMW_h \times NEWF_H)$ 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%.							

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
1306	Capacity Based Demand Response Program Measurement Data Set-Off Settlement Amt	N/A	N/A	**CALCULATIONS FOR _CHARGE TYPE_ 1306 ENDED ON OCTOBER, 2018.** $= MDSF \times (HA_H \times MCMW_h \times AAR)$ 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.	Monthly	Due _IESO_	13	N/A	N/A	N/A	
1307	Capacity Based Demand Response Program Buy-Down Settlement Amount	N/A	N/A	**CALCULATIONS FOR _CHARGE TYPE_ 1307 ENDED ON OCTOBER, 2018.** 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: $= (MCMWR \times BDR \times HAE)$ Where:	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	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 (%)	Comments
				'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 x RD x BDR x HAE) Where: 'BDR' has the same meaning as defined above. '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	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 (%)	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
1315 MRP updated	Capacity Obligation – Availability Charge	CAAC^m_k	4.7J.2.1	**The following was effective prior to the commencement of *market transition*. Refer to section 2 for version in effect on the commencement of *market transition*.** 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 *capacity dispatchable load resource*, as the case may be, for *settlement hour*	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	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 (%)	Comments
				'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 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: (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							

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
				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 *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*.							
1320 MRP updated	Capacity Obligation – Dispatch Test Payment and Emergency Activation Payment	CATAP$^m_{k,h}$ and CAEOP$^m_{k,h}$	9.4.7J.5	**The following was effective prior to the commencement of *market transition*. Refer to section 2 for version in effect on the commencement of *market transition*.** For *capacity auction dispatch test* activations: HDRTAPR × HDRDC$^m_{k,h}$ For *emergency operating state* activations: Max(0, HDRBP $^m_{k,h}$ − Max(0,HOEP$_h$)) × HDRDC $^m_{k,h}$	Hourly	Due MP	13	13	N/A	N/A	
1330	On behalf of the former OPA for the DR2 Program - Availability Payment Settlement Amount	N/A	N/A	**CALCULATIONS FOR *CHARGE TYPE* 1330 ENDED ON FEBRUARY 28, 2015.** = $\sum_H$ CoMW$_h$ x AR x 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.	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	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 (%)	Comments
				'H' is the total On-Peak contract hours in a Contract Month. 'ILSR' (Implied Load Shift Ratio), has the meaning as defined in OPA's DR2 Program Rules and is calculated as follows: ILSR = (-1) x [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	**CALCULATIONS FOR _CHARGE TYPE_ 1331 ENDED ON FEBRUARY 28, 2015.** 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)** $= \sum_H PSO_h \times AR \times CoMW_h \times ILSR$ 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. 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.	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	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 (%)	Comments
				'ILSR' has the same meaning as in CT1330. **B: Availability Set-Off (Timely Confirmation)** $= PSO \times AR \times CoMW_h \times H \times ILSR$ 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)** $= \sum_H PSO \times AR \times (CoMW_h - CMW) \times ILSR$ 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.							

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
				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. **D: Availability Set-Off (Non-Performance)** $= \text{PSO} \times \text{AR} \times \text{CoMW}_h \times \text{H} \times \text{ILSR}$ 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.							

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
1332	On behalf of the former OPA for the DR2 Program - Utilization Payment Settlement Amount	N/A	N/A	**CALCULATIONS FOR *CHARGE TYPE* 1332 ENDED ON FEBRUARY 28, 2015.** The monthly Utilization Payment to a DR2 participant is the sum of the weekly utilization payments for the contract month and calculated as follows: Weekly Utilization payment $= \sum_{P}$ Max[(GHDiff − AHDiff),0] x Min[(CoMWh x 1.15),(Curt $_p$)] x 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 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.	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.
1333	On behalf of the former OPA for the DR2 Program - Utilization Set-Off Settlement Amount	N/A	N/A	**CALCULATIONS FOR *CHARGE TYPE* 1333 ENDED ON FEBRUARY 28, 2015.** 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:	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	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 (%)	Comments
				A: Utilization Set-Off (Reliability) $= \sum_P$ PSO x Max[(GHDiff − AHDiff),0] x CoMWh$_p$ x 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. '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)** $= \sum_P$ PSO x Max[(GHDiff − AHDiff),0] x CoMWh$_p$ x ILSR							*statements* and invoice.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
				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. '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)** $= \sum_P PSO \times Max[(GHDiff - AHDiff),0] \times (CoMWh - CMWh_p) \times ILSR$ This formula applies when the Confirmed MWh are less than the product of the Required Reliability 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.							

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
				'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	****CALCULATIONS FOR _CHARGE TYPE_ 1334 ENDED ON FEBRUARY 28, 2015.**** $= MDSF \times (TD_{k,1330} / NoW_k)$ 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. 'NoW' (Number of Weeks) means the number of Weeks contained in the Contract month. 'k' is the Contract month.	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	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 (%)	Comments
1335	On behalf of the former OPA for the DR2 Program - Buy-Down Settlement Amount	N/A	N/A	**CALCULATIONS FOR _CHARGE TYPE_ 1335 ENDED ON FEBRUARY 28, 2015.** 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 x BDR x 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. '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 x PRCH x BDR x 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.	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.
1336	On behalf of the former OPA for the DR2 Program -	N/A	N/A	**CALCULATIONS FOR _CHARGE TYPE_ 1336 ENDED ON FEBRUARY 28, 2015.**	Monthly	Due DR2-participants Either way	13	N/A	N/A	N/A	Former _OPA_ DR2 Contract. The DR2 program was

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
	Miscellaneous Settlement Amount			Reserved for DR2 payments or charges of a miscellaneous nature not specifically covered under Charge Types 1330 through 1335.							last 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	****CALCULATIONS FOR *CHARGE TYPE* 1340 ENDED ON APRIL 30, 2015.**** $= HA_H \times MCMW_h \times AAR$ 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 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.	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	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 (%)	Comments
1341	On behalf of the former OPA for the DR3 Program – Availability Over-Delivery Settlement Amt	N/A	N/A	**CALCULATIONS FOR *CHARGE TYPE* 1341 ENDED ON APRIL 30, 2015.** $= \sum_H (CMW_h - MCMW_h) \times AODR_h$ 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. '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'.	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.
1342	On behalf of the former OPA for the DR3 Program – Availability Set-Off Settlement Amount	N/A	N/A	**CALCULATIONS FOR *CHARGE TYPE* 1342 ENDED ON APRIL 30, 2015.** The charge to a DR participant is highest of **A**, **B** or **C**: **A: Availability Set-Off (Reliability)** $= \sum_H PSO_h \times AAR \times MCMW_h$ 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.	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	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 (%)	Comments
				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* 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. 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.							

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
				C: Availability Set-Off (Low Confirmation) $= \sum_H (PSO \times AAR \times (MCMW_h - CMW))$ 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. '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	****CALCULATIONS FOR _CHARGE TYPE_ 1343 ENDED ON APRIL 30, 2015.**** $= [\sum_H (Curt_h \times UR_h)] - [\sum_H (NG_h \times MIN(HOEP, UR_h))]$ Where: 'Curt' (Curtailment), 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 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 s_ettlement statements_ and invoice.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
				'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	****CALCULATIONS FOR *CHARGE TYPE* 1344 ENDED ON APRIL 30, 2015.**** The charge to a DR participant is highest of **A**, **B** or **C**: **A: Utilization Set-Off (Reliability)** $= \sum_H PSO_h \times UR \times MCMW_h$ 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)** $= PSO \times UR \times MCMW_h \times CDP$	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	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 (%)	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* 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)** $= \sum_H (PSO \times UR \times (MCMW_h - CMW)$ 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.							

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
1345	On behalf of the former OPA for the DR3 Program – Planned Non-Performance Event Set-Off Amt	N/A	N/A	**CALCULATIONS FOR *CHARGE TYPE* 1345 ENDED ON APRIL 30, 2015.** 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. '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:	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	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 (%)	Comments
				'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. '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	**CALCULATIONS FOR *CHARGE TYPE* 1346 ENDED ON APRIL 30, 2015.** = MDSF x (HA$_H$ x MCMW$_h$ x 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	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	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 (%)	Comments
				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 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	**CALCULATIONS FOR *CHARGE TYPE* 1347 ENDED ON APRIL 30, 2015.** Buy-Down means the act by the Participant of reducing its Monthly Contracted MW and/or removing Daily Schedules from participation in DR3. For the Buy-Down of Monthly Contracted MW the payment is: = (MCMWR x BDR x HAE) 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	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 (%)	Comments
				'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 x RD x BDR x HAE) Where: '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	**CALCULATIONS FOR _CHARGE TYPE_ 1348 ENDED ON APRIL 30, 2015.** 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.
1380	Demand Response 2 Availability Payment Balancing Amount	N/A	N/A	**CALCULATIONS FOR _CHARGE TYPE_ 1380 ENDED ON FEBRUARY 28, 2015.** $\Sigma_K TD_{k,1330}$	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	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 (%)	Comments
				Where 'K' is the set of all DR2 participants 'k'. Where $TD_{k,1330}$ is the *settlement amount* of *charge type* 1330 for the month for DR2 participant 'k'.							*statements* and invoice.
1381	Demand Response 2 Availability Set-Off Balancing Amount	N/A	N/A	**CALCULATIONS FOR *CHARGE TYPE* 1381 ENDED ON FEBRUARY 28, 2015.** $\Sigma_K TD_{k,1331}$ Where 'K' is the set of all DR2 participants 'k'. Where $TD_{k,1331}$ 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.
1382	Demand Response 2 Utilization Payment Balancing Amount	N/A	N/A	**CALCULATIONS FOR *CHARGE TYPE* 1382 ENDED ON FEBRUARY 28, 2015.** $\Sigma_K TD_{k,1332}$ Where 'K' is the set of all DR2 participants 'k'. Where $TD_{k,1332}$ 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.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
1383	Demand Response 2 Utilization Set-Off Balancing Amount	N/A	N/A	**CALCULATIONS FOR *CHARGE TYPE* 1383 ENDED ON FEBRUARY 28, 2015.** $\sum_K TD_{k,1333}$ Where 'K' is the set of all DR2 participants 'k'. Where $TD_{k,1333}$ 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	**CALCULATIONS FOR *CHARGE TYPE* 1384 ENDED ON FEBRUARY 28, 2015.** $\sum_K TD_{k,1334}$ 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'.	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.
1385	Demand Response 2 Buy-Down Balancing Amount	N/A	N/A	**CALCULATIONS FOR *CHARGE TYPE* 1385 ENDED ON FEBRUARY 28, 2015.** $\sum_K TD_{k,1335}$ 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.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
1386	Demand Response 2 Miscellaneous Balancing Amount	N/A	N/A	**CALCULATIONS FOR *CHARGE TYPE* 1386 ENDED ON FEBRUARY 28, 2015.** $\Sigma_K TD_{k,1336}$ 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.
1390	Demand Response 3 Availability Payment Balancing Amount	N/A	N/A	**CALCULATIONS FOR *CHARGE TYPE* 1390 ENDED ON APRIL 30, 2015.** $\Sigma_K TD_{k,1340}$ Where 'K' is the set of all DR3 participants 'k'. Where $TD_{k,1340}$ 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 s*ettlement statements* and invoice.
1391	Demand Response 3 Availability Over-Delivery Balancing Amount	N/A	N/A	**CALCULATIONS FOR *CHARGE TYPE* 1391 ENDED ON APRIL 30, 2015.** $\Sigma_K TD_{k,1341}$ Where 'K' is the set of all DR3 participants 'k'. Where $TD_{k,1341}$ 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	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 (%)	Comments
1392	Demand Response 3 Availability Set-Off Balancing Amount	N/A	N/A	**CALCULATIONS FOR *CHARGE TYPE* 1392 ENDED ON APRIL 30, 2015.** $\sum_K TD_{k,1342}$ Where 'K' is the set of all DR3 participants 'k'. Where $TD_{k,134}$ $_2$ 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	**CALCULATIONS FOR *CHARGE TYPE* 1393 ENDED ON APRIL 30, 2015.** $\sum_K TD_{k,1343}$ Where 'K' is the set of all DR3 participants 'k'. Where $TD_{k,1343}$ 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	**CALCULATIONS FOR *CHARGE TYPE* 1394 ENDED ON APRIL 30, 2015.** $\sum_K TD_{k,1344}$ Where 'K' is the set of all DR3 participants 'k'. Where $TD_{k,1344}$ is the *settlement amount* of *charge type* 1344 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	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 (%)	Comments
1395	Demand Response 3 Planned Non-Event Set-Off Balancing Amount	N/A	N/A	**CALCULATIONS FOR *CHARGE TYPE* 1395 ENDED ON APRIL 30, 2015.** $\sum_K TD_{k,1345}$ Where 'K' is the set of all DR3 participants 'k'. Where $TD_{k,1345}$ 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	**CALCULATIONS FOR *CHARGE TYPE* 1396 ENDED ON APRIL 30, 2015.** $\sum_K TD_{k,1346}$ Where 'K' is the set of all DR3 participants 'k'. Where $TD_{k,1346}$ is the *settlement amount* of *charge type* 1346 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.
1397	Demand Response 3 Buy-Down Balancing Amount	N/A	N/A	**CALCULATIONS FOR *CHARGE TYPE* 1397 ENDED ON APRIL 30, 2015.** $\sum_K TD_{k,1347}$ 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	**CALCULATIONS FOR *CHARGE TYPE* 1398 ENDED ON APRIL 30, 2015.** $\sum_K TD_{k,1348}$	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	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 (%)	Comments
				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'.							*settlement statements* and invoice.
1415	Conservation Assessment Recovery	N/A	N/A	$\sum_{H,M} TD \times (\sum_H{}^{M,T} AQEW_{k,h}{}^{m,t} / (\sum_{K,H}{}^{M,T} AQEW_{k,h}{}^{m,t})$ 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'. Where 'TD' equals the value assessed by the *OEB*.	Monthly	Due Non-LDC Load	13	N/A	N/A	N/A	Implementation details subject to government regulation.
1421	Capacity Agreement Settlement Credit	N/A	N/A	**** CALCULATIONS FOR *CHARGE TYPE* 1421 END DECEMBER 31, 2023 AS PER CONTRACT AGREEMENT**** Calculated as per capacity contracts.	Monthly	Either Way	13	13	N/A	13	
1422	Capacity Agreement Penalty Settlement Amount	N/A	N/A	**** CALCULATIONS FOR *CHARGE TYPE* 1422 END DECEMBER 31, 2023 AS PER CONTRACT AGREEMENT**** Calculated as per capacity contracts.	Monthly	Either Way	13	13	N/A	13	
1423	Energy Sales Agreement Settlement Credit	N/A	N/A	**** CALCULATIONS FOR *CHARGE TYPE* 1423 END DECEMBER 31, 2023 AS PER CONTRACT AGREEMENT**** 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	**** CALCULATIONS FOR *CHARGE TYPE* 1424 END DECEMBER 31, 2023 AS PER CONTRACT AGREEMENT**** Calculated as per energy sales 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	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 (%)	Comments
1428	Small Hydro Program Settlement Amount	N/A	N/A	Manual Entry.	Monthly	Due LDCs either way	TBD	N/A	N/A	N/A	
1465	Ontario Clean Energy Benefit (-10%) Program Balancing Amount	N/A	N/A	** **PROGRAM END DECEMBER 31, 2015** ** $\Sigma_K TD_{k,9992}$ Where 'K' is the set of all *market participants* 'k'. Where $TD_{k,9992}$ 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.
1470	Ontario Electricity Support Program Balancing Amount	N/A	N/A	** *CHARGE TYPE* **1470 REPLACED BY** *CHARGE TYPE* **2470 EFFECTIVE FEBRUARY 1, 2018** ** $\Sigma_H{}^{M,T}(AQEW_{k,h}{}^{m,t} + EGEI_k) \times TP$ 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	N/A	N/A	Implementation details subject to Ontario Regulation 314/15. TP rate subject to OEB regulation
1471	Capacity Agreement Balancing Amount	N/A	N/A	** **CALCULATIONS FOR** *CHARGE TYPE* **1471 END DECEMBER 31, 2023 AS PER CONTRACT AGREEMENT** ** $\Sigma_K TD_{k,1421}$ Where 'K' is the set of all *market participants* 'k'. Where $TD_{k,1421}$ 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	N/A	N/A	** **CALCULATIONS FOR** *CHARGE TYPE* **1472 END DECEMBER 31, 2023 AS PER CONTRACT AGREEMENT** **	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	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 (%)	Comments
	Balancing Amount			$\sum_K TD_{k,1422}$ Where 'K' is the set of all *market participants* 'k'. Where $TD_{k,1422}$ is the total *settlement amount* of *charge type* 1422 for the month for *market participant* 'k'.							
1473	Energy Sales Agreement Balancing Amount	N/A	N/A	**** CALCULATIONS FOR *CHARGE TYPE* 1473 END DECEMBER 31, 2023 AS PER CONTRACT AGREEMENT**** $\sum_K TD_{k,1423}$ Where 'K' is the set of all *market participants* 'k'. Where $TD_{k,1423}$ 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	
1474	Energy Sales Agreement Penalty Balancing Amount	N/A	N/A	**** CALCULATIONS FOR *CHARGE TYPE* 1474 END DECEMBER 31, 2023 AS PER CONTRACT AGREEMENT**** $\sum_K TD_{k,1424}$ Where 'K' is the set of all *market participants* 'k'. Where $TD_{k,1424}$ 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	
1500 MRP retired	Day-Ahead Production Cost Guarantee Payment – Component 1 and	DA_PCG_COMP1	9.4.7D.4	$\sum^T$ (Component 1 – Component1 Clawback) **Component 1:**	Hourly	Either Way	13	N/A	N/A	N/A	**Component 1** applies to Variants 1, 2 and 3.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
	Component 1 Clawback			$-1 \times OP(EMP_h^{m,t}, MIN(DA\_DQSI_{k,h}^{m,t}, DQSI_{k,h}^{m,t}, AQEI_{k,h}^{m,t}), DA\_BE) + DA\_SNLC_{k,h}^m/12$ **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:** $-1 \times OP(EMP_h^{m,t}, MIN(DA\_DQSI_{k,h}^{m,t}, DQSI_{k,h}^{m,t}, AQEI_{k,h}^{m,t}), DIPC_{k,h}^{m,t}) + (DA\_SNLC_{k,h}^m/12) \times (1 - PST_{k,h}^{p,t})$ **Component 1 Clawback:** $-1 \times OP(EMP_h^{m,t}, MIN(MLP\_CONS_{k,h}^{m,t}, AQEI_{k,h}^{m,t}), DIPC_{k,h}^{m,t}) + (DA\_SNLC_{k,h}^m/12) \times (1 - PST_{k,h}^{p,t})$ For a steam turbine resource associated to a pseudo unit: **Component 1:** $-1 \times OP(EMP_h^{m,t}, MIN(DIGQ_{k,h}^{m,t}, DQSI_{k,h}^{m,t}, AQEI_{k,h}^{m,t}), DIPC_{k,h}^{m,t}) + (DA\_SNLC_{k,h}^m/12) \times PST_{k,h}^{p,t}$							**Component 1 Clawback** applies to Variant 2 only. For a description of Production Cost Guarantee Variants, refer to Market Rules 9.4.7D.2.1

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
				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 MRP retired	Day-Ahead Production Cost Guarantee Payment – Component 2	DA_PCG_COMP2	9.4.7D.4	$\sum^T (XDA\_BE_{k,h}^{m,t} - MAX(0, XBE_{k,h}^{m,t}))$ Where: 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 $DIPC_{k,h}^{m,t}.$	Hourly	Either Way	13	N/A	N/A	N/A	**Component 2** applies to Variants 1, 2 and 3. For a description of Production Cost Guarantee Variants, refer to Market Rules 9.4.7D.2.1

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	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 MRP retired	Day-Ahead Production Cost Guarantee Payment – Component 3 and Component 3 Clawback	DA_PCG_COMP3	9.4.7D.4	$\sum^{T} (-1)*(\text{Component 3} + \text{Component 3 Clawback})$ 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: iv) DQSI >= MQSI >= DA_DQSI v) MQSI >= DQSI >= DA_DQSI vi) DQSI > DA_DQSI > MQSI vii) MQSI > DA_DQSI > DQSI viii) DA_DQSI >= DQSI > MQSI ix) DA_DQSI >= MQSI > DQSI **Component 3:** Component 3 is calculated when:	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, refer to Market Rules 9.4.7D.2.1

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
				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: $OP(EMP_h{}^{m,t}, DA\_DQSI_{k,h}{}^{m,t}, BE) - MAX(OP(EMP_h{}^{m,t}, DQSI_{k,h}{}^{m,t}, BE), OP(EMP_h{}^{m,t}, AQEI_{k,h}{}^{m,t}, BE))$ 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:**						

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
				Component 3 Clawback is calculated when:							

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:
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.

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
1503 MRP retired	Day-Ahead Production Cost Guarantee Payment – Component 4	DA_PCG_COMP4	9.4.7D.4	$\sum^T$ ((-1) x [OP(PROR$_{r1,h}{}^{m,t}$, 30R_SQROR$_{r1,k,h}{}^{m,t}$, BR$_{r1,k,h}{}^{m,t}$) + OP(PROR$_{r2,h}{}^{m,t}$, 10NS_SQROR$_{r2,k,h}{}^{m,t}$, BR$_{r2,k,h}{}^{m,t}$) + OP(PROR$_{r3,h}{}^{m,t}$, 10S_SQROR$_{r3,K,h}{}^{m,t}$, BR$_{r3,k,h}{}^{m,t}$)]) 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$_{r1,k,h}{}^{m,t}$)] 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$_{k,h}{}^{m,t}$	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, refer to Market Rules 9.4.7D.2.1

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
1504 MRP retired	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): $DA\_SUC_{k,h}{}^{m} - (DA\_SUC_{k,h}{}^{m} \times 1/12 \times SUC\_INT)$ 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): $DA\_SUC_{k,h}{}^{p} * MLP\_MF * (1 - PST_{k,h}{}^{p,t})$	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, refer to Market Rules 9.4.7D.2.1

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	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, 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:

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
				$DA\_SUC_{k,h}{}^m * (1 - PST_{k,h}{}^{p,t}) * 50\%$ For a steam turbine resource associated to a pseudo unit: $DA\_SUC_{k,h}{}^m * (PST_{k,h}{}^{p,t}) * 50\%$							
1505 MRP retired	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** 'H' is the set of all *settlement hours* 'h' in the DACP start event.	Hourly	Due MP	13	N/A	N/A	N/A	
1510 MRP retired	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:	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	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 (%)	Comments
				$\text{MIN}(0,\sum_{i=1}^{n} (-1) * \text{OP}([\text{MIN}(\text{PD\_EMP}_h^{m,t}, \text{EMP}_h^{m,t}), \text{MLP}_{k,h}^{m,t}, \text{DA\_BE}_{k,h}^{m,t}))$ 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: $\text{MIN}(0,\sum_{i=1}^{n} (-1) * \text{OP}(\text{EMP}_h^{m,t}, \text{MLP}_{k,h}^{m,t}, \text{DA\_BE}_{k,h}^{m,t})$ 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 For resources associated to a pseudo unit, the DA_BE is replaced with $\text{DIPC}_{k,h}^{m,t}$; and the MLP is replaced with MLP_CONS.							
1550 MRP retired	Day-Ahead Production Cost Guarantee Recovery Debit		9.4.8.1.12	$\sum_{H,c}^{M,T} \text{TD}_{k,h,c} \times [(\text{AQEW}_{k,h}^{m,t} + \text{SQEW}_{k,h}^{i,t}) / \sum_k^{M,T} (\text{AQEW}_{k,h}^{m,t} + \text{SQEW}_{k,h}^{i,t})]$ 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'.	Daily	Due *IESO*	13	N/A	0	13	

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
				'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'.							
1560 MRP retired	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	
6000	Ontario Fair Hydro Plan - Regulatory Asset Transfer Amount	N/A	N/A	**REPEALED EFFECTIVE NOVEMBER 1, 2019** 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	**REPEALED EFFECTIVE NOVEMBER 1, 2019** Manual Entry	Monthly	Due *IESO*	N/A	N/A	N/A	N/A	Implementation details subject to government regulations
6147	Class A Global Adjustment Deferral Recovery Amount	N/A	N/A	**** CALCULATIONS FOR *CHARGE TYPE* 6147 END DECEMBER 31, 2021 **** $MDCAA \times (PDF_{k,m,d} / \sum_K PDF_{k,m,d})$ Where 'K' is the set of all *market participants* 'k'.	Monthly	Due *IESO*	13	N/A	N/A	N/A	Ontario Regulation 429/04

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
6148	Class B Global Adjustment Deferral Recovery Amount	N/A	N/A	**** CALCULATIONS FOR *CHARGE TYPE* 6148 END DECEMBER 31, 2021 **** $CBRR \times CBMzP_k$ Where: $CBRR = MDCBA / (\text{Class B Load} - \Sigma_K RPPVA_k)$ 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.: $CBMP_k = \Sigma_H{}^{M,T} AQEW_{k,h}{}^{m,t} + EGEI_k - EEQ - RPPVA_k$ 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'.	Monthly	Due IESO	13	N/A	N/A	N/A	Ontario Regulation 429/04

Charge Type Number	Charge Type Name	Settlement Amount Acronym	Market Rules Reference	Equation	Settlement Resolution	Cashflow	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 (%)	Comments
9147	Class A Global Adjustment Smoothing Balancing Amount	N/A	N/A	**** CALCULATIONS FOR _CHARGE TYPE_ 9147 END DECEMBER 31, 2021 **** $\Sigma_K TD_{k,6147}$ Where 'K' is the set of all market participants 'k'. Where TDk,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	Ontario Regulation 429/04
9148	Class B Global Adjustment Smoothing Balancing Amount	N/A	N/A	**** CALCULATIONS FOR _CHARGE TYPE_ 9148 END DECEMBER 31, 2021 **** $\Sigma_K TD_{k,6148}$ Where 'K' is the set of all market participants 'k'. Where TDk,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	Ontario Regulation 429/04
9992	Ontario Clean Energy Benefit (-10%) Program Settlement Amount	N/A	N/A	****PROGRAM END DECEMBER 31, 2015**** Manual entry based on the values submitted by _market participants_ via on-line settlement forms "Ontario Clean Energy Benefit (-10%) – LDC" and "Ontario Clean Energy Benefit (-10%) – Unit Sub-Meter Provider".	Monthly	Due LDCs and Unit Sub-Meter Providers Either way	0	N/A	N/A	N/A	Implementation details subject to Ontario Regulation 495/10.

3.3.   Rounding Conventions – by Settlement Variable

The following Table 3-3 describes the rounding conventions used in the *settlement process* for each *settlement* variable.

Table 3-3: Rounding Conventions by Settlement Variable

Variable referenced in Section 3.2	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
$AQOR_{r,k,h}{}^{m,t}$	Allocated Quantity of Operating Reserve	1	1	1	• Refer to SQROR.
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.
$CAEO^m{}_{h,k}$	Capacity Auction Energy Offer	N/A	1	1	• Not published via upstream IESO system
CGC	Combined Guaranteed Costs	N/A	2	2	• Not published via upstream *IESO* systems.

Variable referenced in Section 3.2	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
$DA\_BE_{k,h}^{i,t}$	*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.
$DA\_DQSI_{k,h}^{i,t}$	*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.

Variable referenced in Section 3.2	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
$DA\_DQSW_{k,h}^{i,t}$	*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.
$DA\_SNLC_{k,h}^m$	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.

Variable referenced in Section 3.2	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
$DIPC_{k,h}{}^{m,t}$	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*.
$DQSI_{k,h}{}^{m,t}$	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 3.2	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.
$DREBQ_k$	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	Demand Response Scheduled Quantity	N/A	1	1	• 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 Refer to section 3.4	N/A Refer to section 3.4	N/A Refer to section 3.4	• 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.

Variable referenced in Section 3.2	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
$EMP_h^{m,t}$	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.
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* (refer to description of *charge type* 141))	N/A	2	2	• Not published via upstream *IESO* systems.
$HOEP_h$	Hourly Ontario Energy Price	2	2	2	• MIM Publication.
$MAX\_CAP_{k,h}^{m,t}$	Maximum Capacity	2	3	3	
MC_h^m	Minimum Consumption	1	1	1	
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.*

Variable referenced in Section 3.2	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
$MQSW_{k,h}{}^{m,t}$	Market Quantity Scheduled for Withdrawal	1	1	1	
OP	Operating Profit Function	N/A Refer to section 3.4	N/A Refer to section 3.4	N/A Refer to section 3.4	• 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.
$PD\_BE_{k,h}{}^{i,t}$	*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.
$PD\_DQSI_{k,h}{}^{i,t}$	*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.

Variable referenced in Section 3.2	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
$PD\_EMP_h^{m,t}$	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.
$SQEI_{k,h}^{i,t}$	Scheduled Quantity of Energy Injected at an *intertie metering point*	1	1	1	
$SQEW_{k,h}^{i,t}$	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	

3.4.   Rounding Conventions – by Charge Type

Refer to section 2.3 for general information regarding the contents of this Table 3-4 and a description of each column heading.

Table 3-4: Rounding Conventions by Charge Type

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
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.		
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.*		

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
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.		
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.		

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
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: OP(EMP, DQSI, BE) OP(EMP, DQSW, BL) Denominator: 12 Resulting Decimals: 2	(For the calculation outlined in 7.8.4A.16 only) The results are used in the final calculation
120	Local Market Power Debit	2	2	No				
121	Northern Industrial Electricity Rate 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
122	Ramp Down Settlement Amount	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.
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				

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
135	Real-time Import Failure Charge	1	3	Yes	**TERM 1 – Failure Charge** Numerator: EMP + PB_IM − PD_EMP Denominator: 12 Resulting Decimals: 2 **TERM 2 – Price Cap** Numerator: MAX(0,EMP) * RT_ISD Denominator: 12 Resulting Decimals: 2	TERM 1 and TERM 2 compared as applicable.		
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				

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
140	Fixed Energy Rate Settlement Amount	1	3	No				
141	Fixed Wholesale Charge Rate Settlement Amount	1	3	No				
142	Regulated Price Plan 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				
150	Net Energy Market Settlement Uplift	1	3	No				
155	Congestion Management 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
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				
170	Local Market Power Rebate	1	3	No				
171	Northern Industrial Electricity Rate Program Balancing Amount	1	3	No				
183	Generator Cost Guarantee Recovery Debit	1	3	No				
184	Demand Response Debit	2	2	No				
190	Fixed Energy Rate 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
191	Fixed Wholesale Charge Rate Balancing Amount	2	2	No				
198	Renewable Generation Balancing Amount	2	2	No				
200	10 Minute Spinning Reserve Market Settlement Credit	1	2	No				
202	10 Minute Non-spinning Reserve Market Settlement Credit	1	2	No				
204	30 Minute Operating Reserve Market Settlement Credit	1	2	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				

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
406	Emergency Demand Response Credit	2	2	No				
702	Debt Retirement Credit	2	2	No				
704	OPA Administration Credit	2	2	No				
752	Debt Retirement Charge	2	3	No				
754	OPA Administration Charge	1	3	No				
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.		

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
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.		
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.		

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
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			

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
1133	Day-Ahead Generation Cost Guarantee Payment	1	3	No				
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,	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
					PD_BE) OP(PD_EMP, PD_DQSI, PD_BE) Resulting Decimals: 2 **TERM 3 – Price cap** Numerator Max(0,PD_EMP) x DA_ISD Denominator: 12 Resulting Decimals: 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
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) Resulting Decimals: 2	TERM 1, TERM 2 and TERM 3 compared as applicable.		
1137	Intertie Offer Guarantee Reversal	2	2	No				
1139	Intertie Failure Charge Reversal	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
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				
1192	Ontario Fair Hydro Plan Eligible RPP Consumer Discount 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
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				

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
1302	Capacity Based Demand Response Program Availability Set-Off Settlement Amount	1	3	No				
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				

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
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				
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				

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
1315	Capacity Obligation – Availability Charge	1	3	No				
1320	Capacity Obligation – Dispatch Test Payment and Emergency Activation 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 – Availability Set-Off Settlement Amount	1	3	No				
1332	On behalf of *Former* OPA for the DR2 Program – Utilization 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
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				

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
1346	On behalf of *Former* OPA for the DR3 Program – Meter Data Set-Off Settlement Amount	1	3	No				
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				
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				

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
1383	Demand Response 2 Utilization Set-Off Balancing Amount	2	2	No				
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				

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
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 Set-Off Balancing Amount	2	2	No				
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				

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
1398	Demand Response 3 Miscellaneous Balancing Amount	2	2	No				
1415	Conservation Assessment Recovery	1	3	No				
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				
1427	Non-Hydro Renewables Funding Amount	2	2	No				
1465	Ontario Clean Energy Benefit (-10%) Program 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
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				
1474	Energy Sales Agreement Penalty Balancing 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),	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,DA_DQSI, DA_BE) Denominator: 12 Resulting Decimal: 2 Numerator DA_SNLC 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)	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,OPCAP, BE) Resulting Decimal: 2	
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), 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	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
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				
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				

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
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 Smoothing Balancing Amount	1	3	No				
9992	Ontario Clean Energy Benefit (-10%) Program Settlement Amount	2	2	No				

3.5.   Settlement of Physical Bilateral Contracts

3.5.1.   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 3.1 and *charge type* described in section 3.2 of this document.

Table 3-5: Energy Pricing – Location of Bilateral Contract

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 in the overall *settlement amounts* calculated for *charge types* 100 and 101 as per the equations in section 3.2.

3.5.2. The Nature of the Bilateral Contract Quantity

Table 3-6: Bilateral Contract Quantities

Variable	Name	Description
$BCQ_{s,k,h}{}^{m,t}$	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'.
$BCQ_{k,b,h}{}^{m,t}$	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*.

*** Refer to Table 3-6 to Table 3-9 for examples of derived quantities.

Table 3-7: Derived Quantities Example 1

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 (REFER TO SECTION 3.5.3 FOR THE DATA PRESENTATION OF THE BILATERAL CONTRACT QUANTITY)											

Table 3-8: Derived Quantities Example 2

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 (REFER TO SECTION 3.5.3 FOR THE DATA PRESENTATION OF THE BILATERAL CONTRACT QUANTITY)											

Table 3-9: Derived Quantities Example 3

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 (REFER TO SECTION 3.5.3 FOR THE DATA PRESENTATION OF THE BILATERAL CONTRACT QUANTITY)											

Table 3-10: Derived Quantities Example 4

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 (REFER TO SECTION 3.5.3 FOR THE DATA PRESENTATION OF THE BILATERAL CONTRACT QUANTITY)											

3.5.3. 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 – refer to 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* (refer to Chapter 9, section 3.1.6 of the *market rules*) and rounded to the appropriate number of significant digits (refer to section 3.4 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. Refer to section 3.4 of this document for further details.

Table 3-11: Time Resolution of Bilateral Contract Quantities and Rounding

		Location Type	Charge Type	Time Resolution used for Settlements Purposes	Intermediate Rounding Applied within Settlements System?
$BCQ_{s,k,h}{}^{m,t}$	Physical Bilateral Contract Quantity of Energy bought.	Dispatchable *Delivery Point* (injection or withdrawal sub-type)	100	by *metering interval*	Yes – Refer to section 3.4
		Non-Dispatchable *Delivery Point* (injection or withdrawal sub-type)	101	by *settlement hour*	No
		Intertie metering point	100	by *metering interval*	Yes – Refer to section 3.4
$BCQ_{k,b,h}{}^{m,t}$	Physical Bilateral Contract Quantity of Energy sold.	Dispatchable *Delivery Point* (injection or withdrawal sub-type)	100	by *metering interval*	Yes – Refer to section 3.4
		Non-Dispatchable *Delivery Point* (injection or withdrawal sub-type)	101	by *metering interval*	Yes – Refer to section 3.4
		Intertie metering point	100	by *metering interval*	Yes – Refer to section 3.4

3.5.4. 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* (refer to also, *IESO market rules*, Chapter 8, section 2.2.2).

Table 3-12: Allocation of Hourly Uplift Components Between Buying and Selling Market Participants

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.*
Transmission Rights Settlement Credit (TRSC) Hourly Uplift Component	NOT USED	• INCLUDED WITH THE "NET ENERGY MARKET SETTLEMENT CREDIT (NEMSC) Hourly Uplift COMPONENT". • REFER TO NOTE ABOVE.
Transmission Charge Reduction Fund (TCRF) Hourly Uplift Component	NOT USED	• INCLUDED WITH THE "NET ENERGY MARKET SETTLEMENT CREDIT (NEMSC) Hourly Uplift COMPONENT". • REFER TO 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:

$$RQ_{k,h}{}^{m,t} = \sum_{s,b} [BCQ_{k,b,h}{}^{m,t} - BCQ_{s,k,h}{}^{m,t}]$$

Where all variables are defined as per section 3.1.

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 3.1.

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. Refer to section 3.2 for specific listings of *charge types* and their respective equations.

3.6.   Exemptions from the Day-Ahead Import Failure Charge, Day-Ahead Export Failure Charge, and Day-Ahead Linked Wheel Failure Charge

3.6.1.   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)[4].

Generally speaking the applicability of the five Intertie Failure charges[5] 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.

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[4] 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.
[5] 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).

3.6.2.   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.

3.6.3.   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:

- 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.

3.6.4.   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*.

3.6.5.   Decision Logic Applied During the Offer Price Test for Import

PART 1:

The first part of the test ensures that the original *schedule-of-record* schedule $(\mathrm{DA\_DQSI}_{k,h}{}^{i,t})$ for the import transaction is indeed GREATER THAN the resulting *Pre-dispatch schedule* $(\mathrm{PD\_DQSI}_{k,h}{}^{i,t})$ over the course of *settlement hour* 'h'.

IF $\sum^{\mathrm{T}} \mathrm{DA\_DQSI}_{k,h}{}^{i,t} > \sum^{\mathrm{T}} \mathrm{PD\_DQSI}_{k,h}{}^{i,t}$

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 $PD\_BE_{k,h}{}^{i,t}$ (refer to above for definition).
>
> IF $B[2,2] \geq DA\_DQSI_{k,h}{}^{i,t}$ 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 3-1 and 3-2 to refer to 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).

3.6.6. 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 $BL_{k,h}{}^{i,t}$ (refer to 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 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 3-1 and 3-2 to refer to 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).

3.6.7.   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 3.6.5 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 $PD\_BE_{k,h}^{i,t}$ (refer to above for definition).

IF $B[2,2] \geq DA\_DQSI_{k,h}^{i,t}$ 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 3.6.6 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 $BL_{k,h}{}^{i,t}$ (refer to 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**.
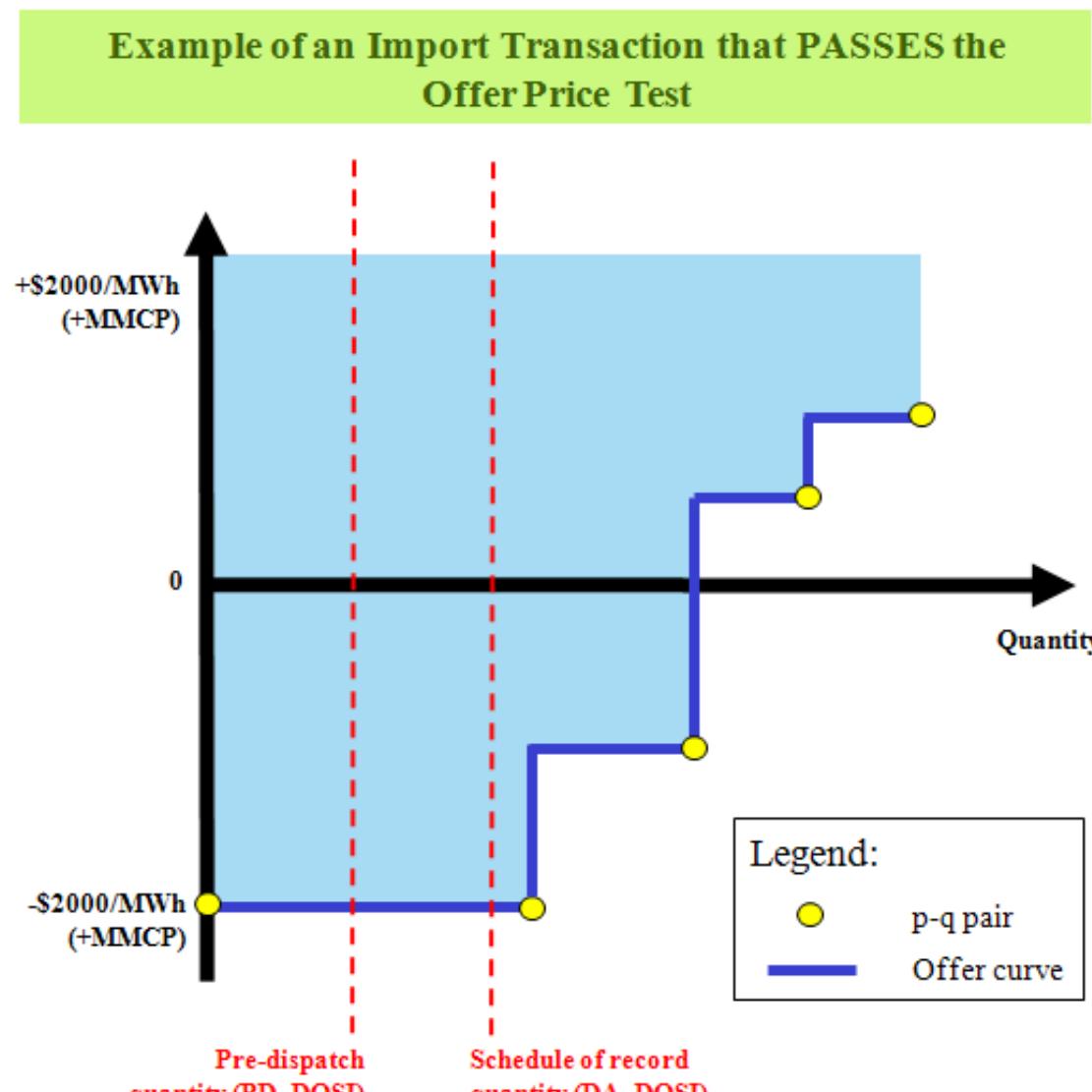
**Figure 3-1: Example of an Import Transaction that PASSES the "Offer Price Test"**
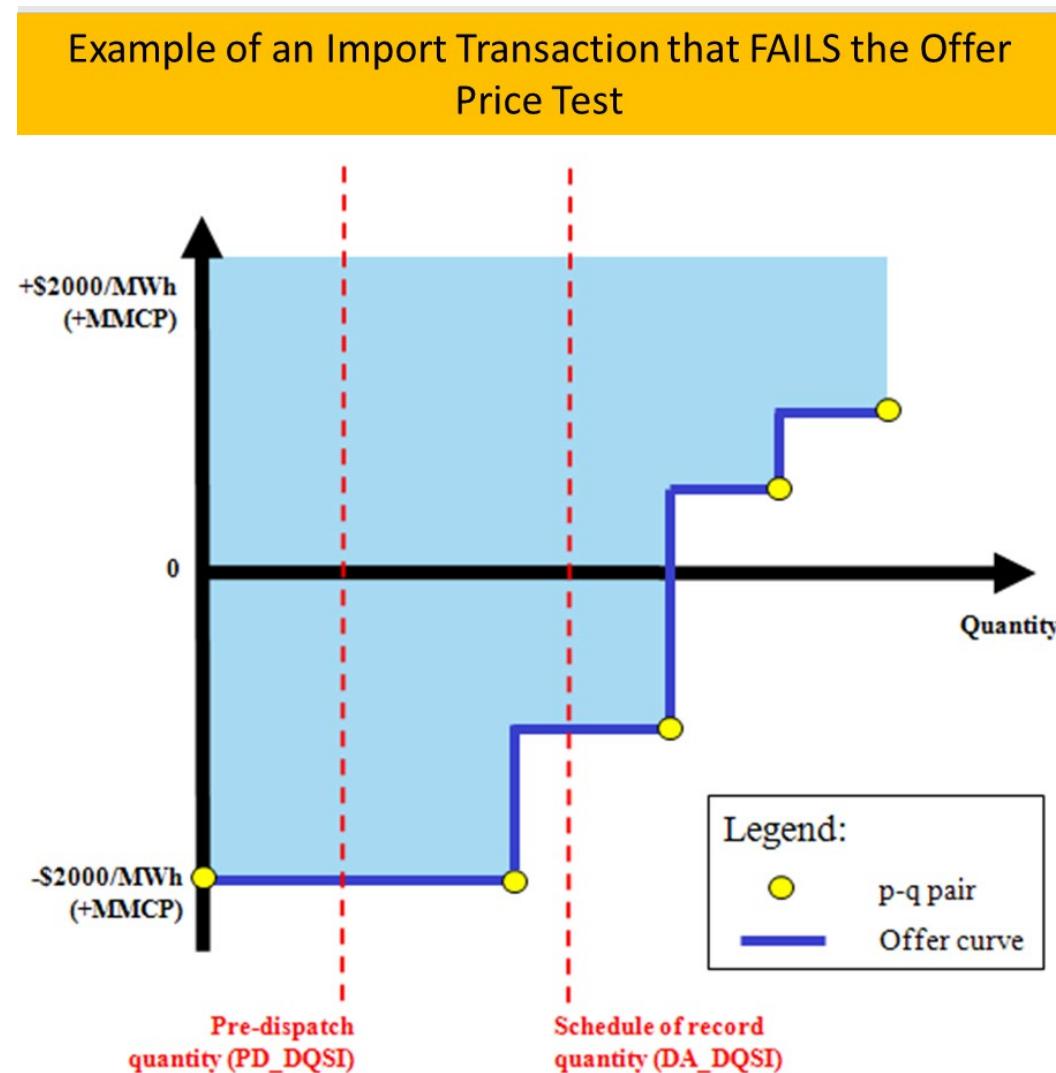
**Figure 3-2: Example of an Import Transaction that FAILS the "Offer Price Test"**
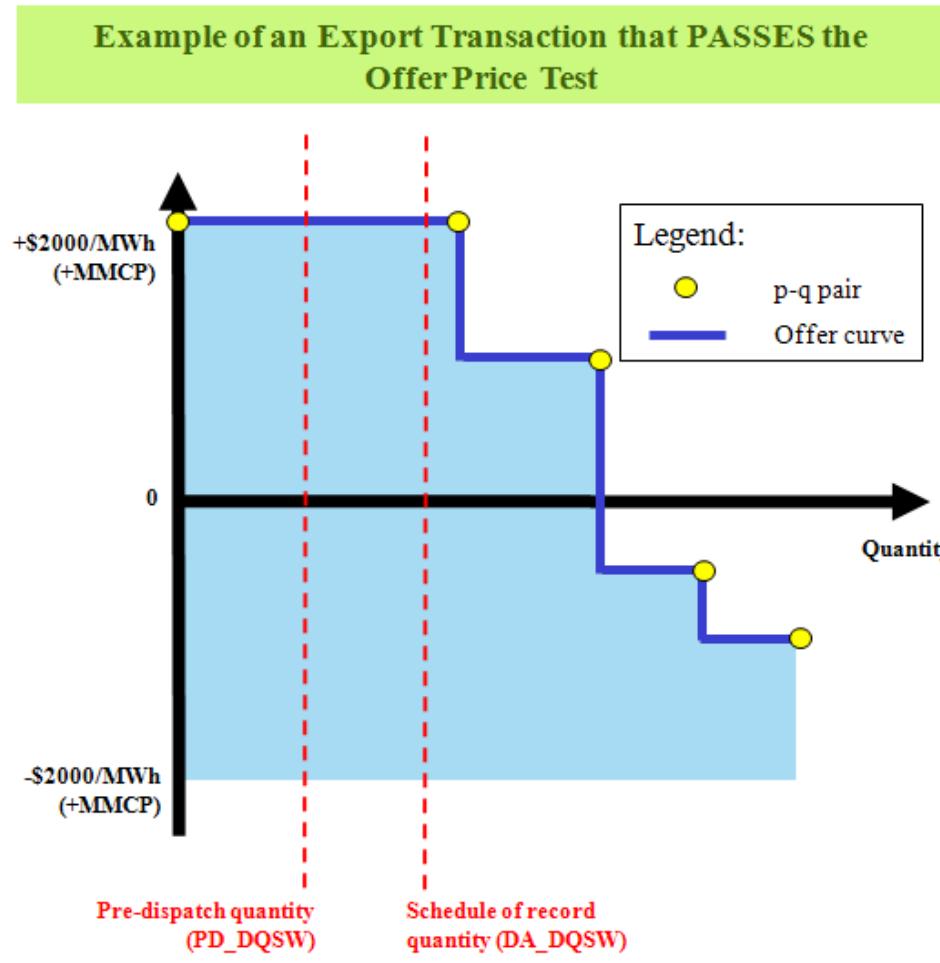
Figure 3-3: Example of an Export Transaction that PASSES the "Offer Price Test"
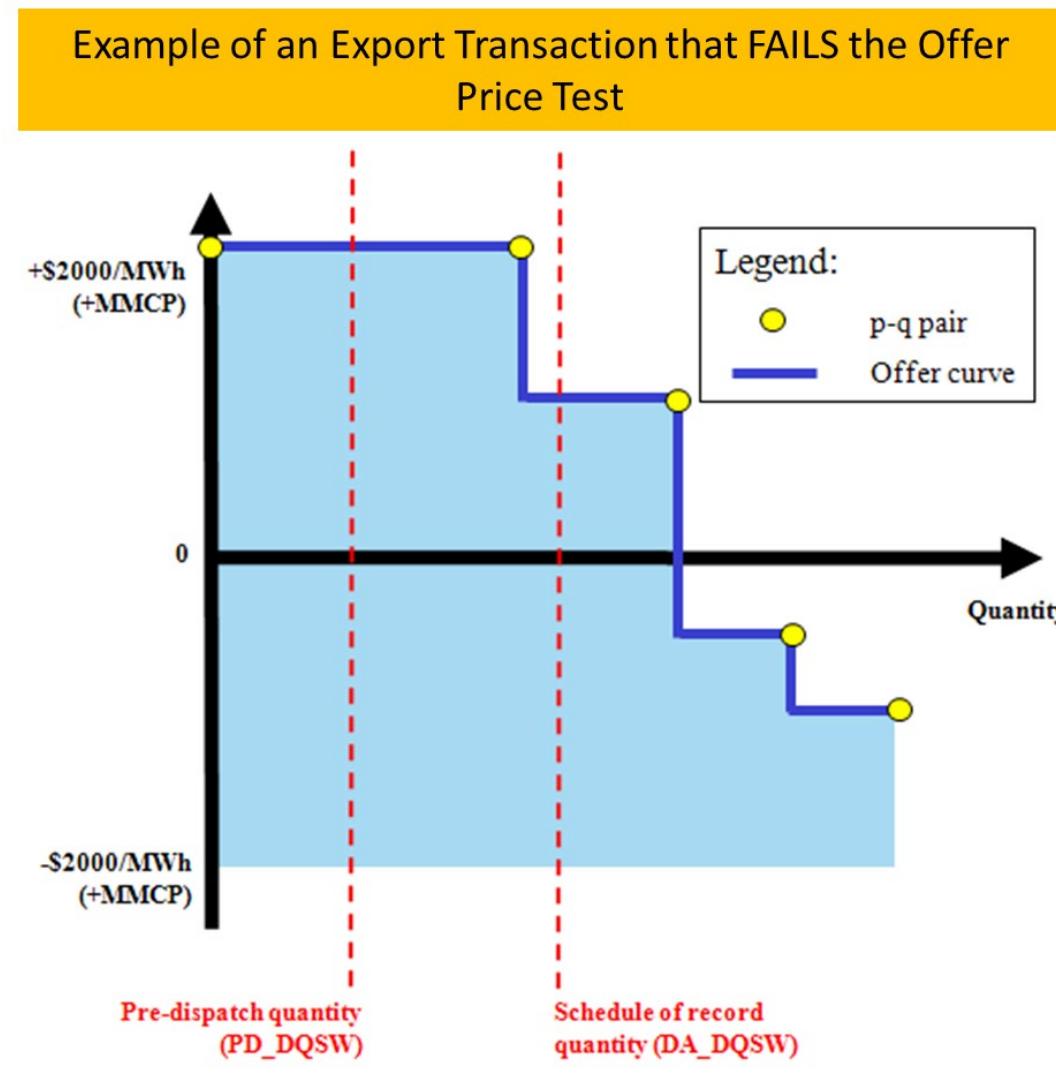
Figure 3-4: Example of an Export Transaction that PASSES the "Offer Price Test"

References

Document Name	Doc ID
Market Rules for the Ontario Electricity Market	RUL-6 to RUL-24
Market Manual 1: Connecting to Ontario's Power System, Part 1.5: Market Registration Procedures	MAN-108
Market Manual 5: Settlements, Part 5.10: Settlement Disagreements	MAN-120
Format Specifications for Settlement Statement Files and Data Files	IMP_SPEC_0005
Ontario Energy Board Act, 1998	
Regulation 436/02	
Regulation 330/09	
Regulation 98/05	
Regulation 314/15	
Regulation 442/01	
Electricity Act, 1998	
Regulation 429/04	
Regulation 493/01	
Regulation 494/01	
Ontario Rebate for Electricity Consumers Act, 2016	
Regulation 363/16	
Regulation 364/16	
Electricity Restructuring Act, 2004	
Bill 4, Ontario Energy Board Amendment Act (Electricity pricing), 2003	Bill 4

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