

PUBLIC

LIST

# IESO Charge Types and Equations

Issue 4.1

November 17, 2025

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

**LST-84**

**IMP\_LST\_0001**

Document Change History

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| Refer to Issue 86.0 (IMP\_LST\_0001) for changes prior to Market Transition. | | |
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| 2.0 | Issued in advance of MRP Go Live – May 1, 2025 | April 25, 2025 |
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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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Table of Changes

| 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 –

## Introduction

### 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.

### 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](https://www.ieso.ca/-/media/Files/IESO/Document-Library/Market-Rules-and-Manuals-Library/market-manuals/settlements/se-StatementAndDataFileFormatSpec.ashx) document located on the [Technical Interfaces](https://www.ieso.ca/en/Sector-Participants/Technical-Interfaces) webpage under ‘Commercial Reconciliation’.

This document is structured as follows:

[Section 2](#_Active_IESO_Charge)**:** Active *IESO* Charge Types and Equations

[Section 2.1](#_Variable_Descriptions)**:** This section contains a description of the variables that are specific to *charge types* associated with *applicable law* within [section 2.2](#_Charge_Types_and). 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](#_Charge_Types_and): 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](#_Rounding_Conventions_–): This section contains a description of rounding conventions for *charge type* calculations within [section 2.2](#_Charge_Types_and).

[Section 2.4](#_Settlement_of_Physical): 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):Inactive *IESO* Charge Types and Equations

Similar to subsections within [section 2](#_Active_IESO_Charge), however the provisions of [section 3](#_Inactive_IESO_Charge) 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](#_Exemptions_from_the) 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.

### 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*.

### Contact Information

Changes to this document are managed via the [*IESO* Change Management process](http://www.ieso.ca/sector-participants/change-management/overview). Stakeholders are encouraged to participate in the evolution of this document via this process.

As part of the authorization and registration process[[1]](#footnote-2), *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*.

To contact the *IESO*, youcan email *IESO* Customer Relations at [customer.relations@ieso.ca](mailto:customer.relations@ieso.ca) or use telephone or mail. Telephone numbers and the mailing address can be found on the [*IESO* website](http://www.ieso.ca/corporate-ieso/contact). *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 –

## 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.*

### 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](#_Charge_Types_and).

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]](#footnote-3) | 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. |
| EGEIk | Embedded Generator Energy Injection | The total volume of *energy* (MWh) supplied by *embedded generator*s during the month to *distributors* who are *market participants* and to all embedded distributors to whom the *market participant* ‘k’ is the host *distributor*, adjusted for losses as required by the *OEB*, Retail Settlement Code. | 3 | Refer to regulations. |
| ETS | Export Transmission Service Tariff Rate | Export Transmission Service Tariff Rate in units of $/MWh. | 2 | Subject to the OEB “Ontario Transmission Rate Order”. |
| GA\_AQEWg,k,h,Mm,t | Allocated Quantity of Energy Withdrawn for elements of the Global Adjustment distribution | Allocated quantity in MWh of *energy* withdrawn by *market participant* or Distributor ‘k*’* at *RWM* ‘m’ in *metering interval* ‘t’ of *settlement hour* ‘h’ in month ‘M’ for element “g”.  Where ‘g’ is 1 for Class A Market Participant or Consumer load, and 2 for *energy* withdrawn by Generator ‘k’ in the course of providing Ancillary Services. |  | Refer to regulations. |
| GARB | Global Adjustment Rate for Class B | GA Class B Rate. |  | Refer to regulations. |
| GRP | Generator Regulated Price | A regulated price ($/MWh) with respect to output of OPG’s regulated generating stations, set by the *OEB.* | 2 | Subject to regulation by the *Ontario Energy Board*. |
| LCDk,hm | 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 LCDk,hm denotes the non-coincident peak demand for the month. | 3 | Subject to the OEB “Ontario Transmission Rate Order”. |
| NSDk,hm | Network Service Demand (KW) | The Billing Demand for Network Transmission Service (KW) is defined as the higher of:  transmission customer coincident peak demand (KW) in the hour of the month when the total hourly demand of all PTS customers is highest for the month; and  85% of the customer peak demand in any hour during the peak period 7 AM to 7 PM (local time) on *business days* defined by the *IESO*.  For the purposes of determining business days for calculating transmission charges, the IESO uses the holidays identified by the Ontario Energy Board.  The peak period hours will be between 0700 and 1900 hours Eastern Standard Time during winter (i.e. during standard time) and 0600 to 1800 hours during summer (i.e. during daylight savings time), in conformance with the meter time standard used by the *IESO* settlement systems. | 3 | Subject to the OEB “Ontario Transmission Rate Order”. |
| PDFk,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.* |
| PGSh,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 ($/KW) | Transformation Connection Service Transmission Tariff Rate in units of dollars per kilowatt. | 2 | Subject to the OEB “Ontario Transmission Rate Order”. |
| RPPl | Regulated Price Plan | A fixed *energy* rate for all *metering intervals* based on consumption level l. |  | Subject to regulation by the *Ontario Energy Board.* |
| TCDk,hm | Transformation Connection Demand (KW) | Billing Demand for Transformation Connection Transmission Service (KW) for *transmission customer* ‘k’ at transmission delivery point m during *settlement hour* ‘h’ in which TCDk,hm denotes the non-coincident peak demand for the month. | 3 | Subject to the OEB “Ontario Transmission Rate Order”. |
| TDk,h,c | Total Market Settlement Amount | Total *settlement amount* (dollars) for the market used in *hourly uplift* and calculations for various other non-hourly *settlement amounts* for *market participant* ‘k’ or *transmission customer* ‘k’ during *settlement hour* ‘h’ with respect to *charge type* ‘c’. | N/A | This is purely a notational term is used within the documentation to describe the aggregation of various *settlement amounts.*  A summation across *charge type* ‘c’ denotes an aggregation of all *settlement amounts* for that *charge type* for the time period concerned.  e.g.: cT  indicates a summation of all *settlement amounts* for *charge type* ‘c’ during all *metering intervals* ‘T’. |
| TLQ | Threshold Load Quantity | A threshold (kWh) with respect to monthly consumption of regulated customers, set by the *OEB.* |  | Subject to regulation by the *Ontario Energy Board.* |
| TPc | Tariff price | A stipulated rate ($/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*. |
| Uk | 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. |

### 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](#_Toc140737042) 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. |
| 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. |

#### Financial Market Charge Types and Equations

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

| 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 | | Equation for Transmission Rights Auction Settlement Debit  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 | |  | |

Table 2‑3: Financial Market Charge Types and Equations

#### 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:**  Equation for TR Clearing Account Credit for loads  **For exporters:**  Equation for TR Clearing Account Credit for exporters  **Where:**   1. TRCADL =(  KTDC / KTDC,C1 ) x TRCAD 2. TRCADE = ( KTDC1 / KTDC,C1 ) x TRCAD 3. 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*; 4. C = the set of all monthly service *charge types* ‘c’ as follows: 650,651,652; 5. C1 = the set of all monthly export transmission *charge types* ‘c’ as follows: 653; 6. H = the set of all s*ettlement hours* ‘h’ in the *energy market billing periods* immediately preceding the current *energy market billing period*, as determined by *IESO Board*; 7. 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*; 8. 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*; 9. 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 10. 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*. | Monthly (when applicable) | Due MP | 13 | N/A | 0 | 13 | The *billing period* is defined in  MM5.5: IESO-Administered Markets 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*:   Transmission Rights Settlement Credit   1. If the withdrawal TR zone of the *transmission right* is in the *IESO control area*:   Transmission Rights Settlement Credit  **Where:**   1. = the *day-ahead market* external congestion price for *energy* in injection *TR zone* ‘iz’ in *settlement hour* ‘h’; and 2. = the *day-ahead market* external congestion price for *energy* in withdrawal *TR zone* ‘jz’ in *settlement hour* ‘h’. | Hourly | Due MP | 0 | 0 | 0 | 0 |  |
| 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 | Equation for Emergency Energy Rebate  Where ‘H’ is the set of all *settlement hours* ‘h’ in the month.  Where ‘T’ is the set of *all metering intervals*‘t’ in the set of all *settlement hours* ‘H’. | Monthly | Due MP | 13 | N/A | 0 | 13 |  |
| 119  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\*\***    Equation for Station Service Reimbursement Credit  **Where:**   1. T = the set of all *metering intervals* in *settlement hour* ‘h’; 2. M = the eligible *generation station service* *delivery point* ‘m’ of *market participant* ‘k’; 3. 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; 4. 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*; 5. K = the set of all *market participants;* 6. 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; 7. C3 = the set of the following daily *charge type* ‘c’ as follows: 1119,1850,1851,1960,1967,1971,1982,1986; 8. H = the set of all *settlement hours* ‘h’ in the *billing period*; 9. 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*; 10. H3 = the set of all *settlement hours* ‘h’ in the day; and 11. 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 | Equation for Northern Energy Advantage Program Settlement Amount  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. |
| 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:**  Regulated price plan settlement amount equation | 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 Adjustment Amount | N/A | Equation for Regulated Nuclear Generation Adjustment Amount for dispatchable delivery points  Where ‘T’ is the set of 12 *metering intervals* ‘t’ during *settlement hour* ‘h’. | Interval  or  Hourly | Due OPG | 13 | N/A | N/A | N/A | Eligibility, rates, and other implementation details subject to government regulation. |
| 145 | Regulated Hydroelectric Generation Adjustment Amount | N/A | For *dispatchable resources*:  Equation for Regulated Hydroelectric Generation Adjustment Amount  **Incentive Payment = DAM Incentive + RT Incentive**  Equation for Regulated Hydroelectric Generation Adjustment Amount  Equation for Regulated Hydroelectric Generation Adjustment Amount  For *non-dispatchable resources*:  Equation for Regulated Hydroelectric Generation Adjustment Amount  Equation for Regulated Hydroelectric Generation Adjustment Amount  Or  Equation for Regulated Hydroelectric Generation Adjustment Amount  **Where:**  is the average DAM hourly scheduled MW over a trade day  is the average hourly metered quantity over a trade day  “H” is all hours in the trade day | Monthly | Due OPG | 13 | N/A | N/A | N/A | Eligibility, rates, and other implementation details subject to *OEB* regulation. |
| 147 | Class A – Global Adjustment Settlement Amount | N/A | Equation for Class A – Global Adjustment Settlement Amount  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.:  H,M,CTD – TD147) x  MAX(( HM,TAQEWk,hm,t + EGEIk -EEQ),0) / Class B Load  For other Class B *Market Participants* and Distributors:  H,M,CTD – TD147) x  MAX(( HM,TAQEWk,hm,t + EGEIk - GA\_AQEWg,k,h,Mm,t – PGSh,M ),0) / Class B Load  Class  B Load =  (K (MAX(HM,T AQEWk,hm,t +EGEIk - EEQ - HM,T GA\_AQEWg,k,h,Mm,t -  PGSh,M ,0))) -K Uk  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.** | Monthly | Either Way | 13 | N/A | N/A | N/A | Eligibility, rates, and other implementation details subject to government regulation. |
| 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 | Equation for Outage Cancellation/ Deferral 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. | 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 | Equation for Unrecoverable Testing Costs 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’. | Monthly | Due *IESO* | 13 | N/A | 0 | 13 |  |
| 166 | Tieline Maintenance Reliability Debit | MR Ch.9 s.4.14.12  and  MR Ch.5 s.5.3.4 | Equation for Tieline Reliability Maintenance 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’. | 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 | Equation for Emergency Energy Debit  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:**  Equation for TR Market Shortfall Debit for loads  **For exporters:**  Equation for TR Market Shortfall Debit for exporters  **Where:**   1. TRCADL =(  KTDC / KTDC,C1 ) x TRCAR 2. TRCADE = ( KTDC1 / KTDC,C1 ) x TRCAR 3. 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*; 4. 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*; 5. C = the set of all monthly service *charge types* ‘c’ as follows: 650,651,652; and 6. C1 = the set of all monthly export transmission *charge types* ‘c’ as follows:653*.* | Monthly | Due *IESO* | 13 | N/A | 0 | 13 |  |
| 169 | Station Service Reimbursement Debit | MR Ch.9 ss.2.2.12-2.2.17  and  4.14.12 | Equation for Station Service Reimbursement Debit  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 | Equation for Northern Energy Advantage Program Balancing Amount  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 | Equation for MACD Enforcement Activity Balancing Amount  Where ‘K’ is the set of all *market participants* ‘k’.  Where TDk123 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\*\***  Equation for MACD Enforcement Activity Balancing Amount  **Where:**   1. C = the set of all *charge types* ‘c’ as follows: 1828,1829,1928,1929. | Hourly | Due MP | 13 | N/A | 0 | 13 |  |
| 192 | Regulated Price Plan Balancing Amount | N/A | Equation for Regulated Price Plan Balancing Amount  Where ‘K’ is the set of all *market participants* ‘k’.  Where TDk,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 | TD143 | Monthly | Due *IESO* | 0 | N/A | N/A | N/A | Implementation details subject to government regulation. |
| 194 | Regulated Nuclear Generation Balancing Amount | N/A | TD144 | 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 | TD145 | Monthly | Due *IESO* | 0 | N/A | N/A | N/A | Implementation details subject to *OEB* regulation. |
| 196 | Global Adjustment Balancing Amount | N/A | Equation for Global Adjustment Balancing Amount  Where ‘K’ is the set of all *market participants*‘k’.  Where TDk,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 Balancing Amount | N/A | Equation for Global Adjustment - Special Programs Balancing Amount  Where ‘K’ is the set of all *market participants*‘k’.  Where TDk,1466 is the *settlement amount* of *charge type*1466 for the month for *market participant* ‘k’. | Monthly | Due *IESO* | 0 | N/A | N/A | N/A | Implementation details subject to government regulation. |
| 199 | Regulated Price Plan Retailer Balancing Amount | N/A | Equation for Regulated Price Plan Retailer Balancing Amount  Where ‘K’ is the set of all *market participants* ‘k’.  Where TDk,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 | Equation for 10 Minute Spinning Reserve Market Shortfall Rebate  **Where:**   1. 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 | Equation for 10 Minute Non-spinning Reserve Market Shortfall Rebate  **Where:**   1. 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 | Equation for 30 Minute Operating Reserve Market Shortfall Rebate  **Where:**   1. C = the set of all *charge types* ‘c’ as follows: 255. | Hourly | Due MP | 13 | N/A | 0 | 13 |  |
| 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**  *Equation for 10-Minute Spinning Non-Accessibility Settlement Amount For Dispatchable Loads and Non-Aggregated Generation Resources*  **Where:**   1. **For a *dispatchable electricity storage resource* or a non-aggregated *dispatchable generation resource*:** 2. = the maximum limit used in determining the *real-time schedule* in the *dispatch scheduling* and pricing process 3. **For a *dispatchable load*:** 5. = 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 Resourcesthat are not Pseudo-Units**  Equation for 10-Minute Spinning Non-Accessibility Settlement Amount For aggregated generation resources non-pseudo-units  **Where:**   1. M = the set of all *delivery points* ‘m’ of the aggregated group of *dispatchable generation resources* 2. = the maximum limit used in determining the *real-time schedule* in the *dispatch scheduling* and pricing pass 3. is calculated as: 4. 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. 5. is calculated as: 6. is calculated as follows for each type of *class r reserve*: 7. When = 0, then = 0, and when > 0, then is calculated as follows:   Transmission Rights Settlement Credit  **Dispatchable Generation Resourcesthat are Pseudo-Units**   1. **For a combustion turbine *resource:***   10-Minute Spinning Non-Accessibility Settlement Amount  **Where:**   1. ‘M’ = the set of all *delivery points* ‘c’ and ‘s’ of the aggregated group of *dispatchable generation resources* 2. is calculated as:   **Equation for calculation ORIA**  **Equation for calculation ORIA**  **and where:**  **Equation for 10-Minute Spinning Non-Accessibility Settlement Amount for a combustion turbine generation unit of generation resources that are pseudo-units - Conditions**   1. **For a steam turbine *resource:***   *10-Minute Spinning Non-Accessibility Settlement Amount*  Equation for calculating ORIA  **and where:**  **Equation for 10-Minute Spinning Non-Accessibility Settlement Amount for a steam turbine generation unit of generation resources that are pseudo-units - Conditions**   1. P1 = the set of the *resource’s pseudo-units* ‘p’ where >= *minimum loading point* and is not operating in *single cycle mode*; 2. C1 = the set of the *resource’s* combustion turbine *resources* ‘c’ associated with the steam turbine *resource* and >= *minimum loading point* and is not operating in *single* *cycle* *mode*; and 3. D = the set of *pseudo-unit* operating regions ‘d1’, ‘d2’, and ‘d3’.   **For both the combustion turbine *resource* and the steam turbine *resource***  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.  **Equation for 10-Minute Spinning Non-Accessibility Settlement Amount for both the combustion turbine generation unit and the steam turbine generation unit of :generation resources that are pseudo-units**  **Where:**   1. ‘M’ = the set of all *delivery points* ‘c’ and ‘s’ of the aggregated group of *dispatchable generation resources* 2. for the combustion turbine *resource* is calculated as: 3. for the steam turbine *resource* is calculated as: 4. for the combustion turbine *resource* is calculated as follows for each type of *class r reserve*: 5. for the steam turbine *resource* is calculated as follows for each type of *class r reserve*: 6. for the combustion turbine *resource* 7. for the steam turbine *resource* 8. When =0, then =0, and when >0, then   **10-Minute Spinning Non-Accessibility Settlement Amount** | Interval | Due *IESO* | 13 | N/A | N/A | N/A |  |
| 208  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**  *10-Minute Non-Spinning Non-Accessibility Settlement Amount*  **Where:**   1. **For a *dispatchable electricity storage resource* or a non-aggregated *dispatchable generation resource*:** 3. = the maximum limit used in determining the *real-time schedule* in the *dispatch scheduling* and pricing process   Equation for 10-Minute Non-Spinning Accessibility Settlement Amount for dispatchable loads and non-aggregated generation resources - conditions  **Aggregated Dispatchable Generation Resourcesthat are not Pseudo-Units**  Equation for 10-Minute Non-Spinning Accessibility Settlement Amount for aggregated generation resources non-pseudo-units  **Where:**   1. ‘M’ = the set of all *delivery points* ‘m’ of the aggregated group of *dispatchable generation resources* 2. = the maximum limit used in determining the *real-time schedule* in the *dispatch scheduling* and pricing process 3. is calculated as:   **10-Minute Non-Spinning Non-Accessibility Settlement Amount**   1. 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. 2. is calculated as:   10-Minute Non-Spinning Non-Accessibility Settlement Amount   1. is calculated as follows for each type of *class r reserve*: 2. When = 0, then = 0, and when > 0, then is calculated as follows:   10-Minute Non-Spinning Non-Accessibility Settlement Amount  **Dispatchable Generation Resourcesthat are Pseudo-Units**   1. **For a combustion turbine *resource:***   **Where:**   1. ‘M’ = the set of all *delivery points* ‘c’ and ‘s’ of the aggregated group of *dispatchable generation resources*; 2. is calculated as:   10-Minute Non-Spinning Non-Accessibility Settlement Amount  **and where:**   1. when>= *minimum loading point* 2. 0 when < *minimum loading point* 3. **For a steam turbine *resource:***   10-Minute Non-Spinning Non-Accessibility Settlement Amount  **Where:**   1. ‘M’ = the set of all *delivery points* ‘c’ and ‘s’ of the aggregated group of *dispatchable generation resources* 2. is calculated as:   **and where:**   1. = 2. P1 = the set of the *resource’s pseudo-units* ‘p’ where >= *minimum loading point* and is not operating in single cycle mode; 3. C1 = the set of the *resource’s* combustion turbine *resources* ‘c’ associated with the steam turbine *resource* and >= *minimum loading point* and is not operating in single cycle mode; and 4. D = the set of *pseudo-unit* operating regions ‘d1’, ‘d2’, and ‘d3’.   **For both the combustion turbine *resource* and the steam turbine *resource***  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.  **Equation for 10-Minute Non-Spinning Accessibility Settlement Amount for both the combustion turbine generation unit and the steam turbine generation unit for resources that are pseudo-units**  **Where:**   1. ‘M’ = the set of all *delivery points* ‘c’ and ‘s’ of the aggregated group of *dispatchable generation resources* 2. for the combustion turbine *resource* is calculated as:   10-Minute Non-Spinning Non-Accessibility Settlement Amount   1. for the steam turbine *resource* is calculated as:   10-Minute Non-Spinning Non-Accessibility Settlement Amount   1. for the combustion turbine *resource* is calculated as follows for each type of *class r reserve*: 2. for the steam turbine *resource* is calculated as follows for each type of *class r reserve*: 3. for the combustion turbine *resource* 4. for the steam turbine *resource* 5. When =0, then =0, and when >0, then   10-Minute Non-Spinning Non-Accessibility Settlement Amount | Interval | Due *IESO* | 13 | N/A | N/A | N/A |  |
| 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**  **Equation for 30-Minute Non-Accessibility Settlement Amount for dispatchable loads and non-aggregated generation resources**  **Where:**   1. **For a *dispatchable electricity storage resource* or a non-aggregated *dispatchable generation resource*:** 3. = the maximum limit used in determining the *real-time schedule* in the *dispatch scheduling* and pricing process   Equation for 30-Minute Non-Accessibility Settlement Amount for dispatchable loads and non-aggregated generation resources - conditions  **Aggregated Dispatchable Generation Resourcesthat are not Pseudo-Units**  Equation for 30-Minute Non-Accessibility Settlement Amount for aggregated generation resources non-pseudo-units  **Where:**   1. ‘M’ = the set of all *delivery points* ‘m’ of the aggregated group of *dispatchable generation resources* 2. = the maximum limit used in determining the *real-time schedule* in the *dispatch scheduling* and pricing process 3. is calculated as:   **30-Minute Non-Accessibility Settlement Amount**   1. 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. 2. is calculated as:   **30-Minute Non-Accessibility Settlement Amount**   1. is calculated as follows for each type of *class r reserve*: 2. When = 0, then = 0, and when > 0, then is calculated as follows:   **30-Minute Non-Accessibility Settlement Amount**    **Dispatchable Generation Resourcesthat are Pseudo-Units**   1. **For a combustion turbine *resource:***   30-Minute Non-Accessibility Settlement Amount  Equation for 30-Minute Non-Accessibility Settlement Amount for generation resources that are pseudo-units - conditions   1. **For a steam turbine *resource:***   *30-Minute Non-Accessibility Settlement Amount*  **Where:**   1. ‘M’ = the set of all *delivery points* ‘c’ and ‘s’ of the aggregated group of *dispatchable generation resources*   30-Minute Non-Accessibility Settlement Amount  **and where:**   1. = 2. P1 = the set of the *resource’s pseudo-units* ‘p’ where >= *minimum loading point* and is not operating in single cycle mode; 3. C1 = the set of the *resource’s* combustion turbine *resources* ‘c’ associated with the steam turbine *resource* and >= *minimum loading point* and is not operating in single cycle mode; and 4. D = the set of *pseudo-unit* operating regions ‘d1’, ‘d2’, and ‘d3’.   **For both the combustion turbine *resource* and the steam turbine *resource***  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.  **Equation for 30-Minute Non-Accessibility Settlement Amount for both the combustion turbine generation unit and the steam turbine generation unit of generation resources that are pseudo-units**  **Where:**   1. ‘M’ = the set of all *delivery points* ‘c’ and ‘s’ of the aggregated group of *dispatchable generation resources* 2. for the combustion turbine *resource* is calculated as:   30-Minute Non-Accessibility Settlement Amount   1. for the steam turbine *resource* is calculated as:   30-Minute Non-Accessibility Settlement Amount   1. for the combustion turbine *resource* is calculated as follows for each type of *class r reserve*: 2. for the steam turbine *resource* is calculated as follows for each type of *class r reserve*: 3. for the combustion turbine *resource* 4. for the steam turbine *resource* 5. When =0, then =0, and when >0, then   30-Minute Non-Accessibility Settlement Amount | Interval | Due *IESO* | 13 | N/A | N/A | N/A |  |
| 212  MRP new | Day-Ahead Market 10-Minute Spinning Reserve Settlement Credit  (HORSA{1}) | MR Ch.9 s.3.1.10 | Equation for Day-Ahead Market 10-Minute Spinning Reserve Settlement Credit | Hourly | Due MP | 13 | N/A | N/A | N/A |  |
| 213  MRP new | Real-Time 10-Minute Spinning Reserve Settlement Credit  (HORSA{2}) | MR Ch.9 s.3.1.11 | Equation for Real-Time 10-Minute Spinning Reserve Settlement Credit | 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 | Equation for Day-Ahead Market 10-Minute Non-Spinning Reserve Settlement Credit | 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 | Equation for Real-Time 10-Minute Non-Spinning Reserve Settlement Credit | Interval | Either Way | 13 | 13 | 13 | 13 |  |
| 216  MRP new | Day-Ahead Market 30-Minute Operating Reserve Settlement Credit  (HORSA{1}) | MR Ch.9 s.3.1.10 | Equation for Day-Ahead Market 30-Minute Operating Reserve Settlement Credit | Hourly | Due MP | 13 | 13 | 13 | 13 |  |
| 217  MRP new | Real-Time 30-Minute Operating Reserve Settlement Credit  (HORSA{2}) | MR Ch.9 s.3.1.11 | Equation for Real-Time 30-Minute Operating Reserve Settlement Credit | 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\*\***  **Euqation for 10-Minute Spinning Reserve Hourly Uplift**  **Where:**   1. 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  (ORSSDk,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 ORESFk,r,hm,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  (HUSA) | MR Ch.9 s.3.11 | **\*\*The set of *charge types* ‘c’ has been updated\*\***  **Equation for 10-Minute Non-Spinning Reserve Hourly Uplift**  **Where:**   1. C = the set of all *charge types* ‘c’ as follows: 208,214,215. | Hourly | Due *IESO* | 13 | N/A | 0 | 13 |  |
| 253 | 10 Minute Non-spinning Market Reserve Shortfall Debit  (ORSSDk,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 ORESFk,r,hm,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\*\***  30 Minute Operating Reserve Hourly Uplift  **Where:**   1. 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  (ORSSDk,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 ORESFk,r,hm,t shall be set at zero equals ∞. | Interval | Due *IESO* | 13 | 13 | N/A | N/A |  |
| 400 | Black Start Capability Settlement Credit | 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 Settlement Credit | 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 |  |
| 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 | Equation for Black Start Capability 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’. | Monthly | Due *IESO* | 13 | N/A | 0 | 13 |  |
| 451 | Hourly Reactive Support and Voltage Control Settlement Debit | MR Ch.9 s.4.2.4 | Equation for Hourly Reactive Support and Voltage Control Settlement Debit  **Where:**   1. 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 | Equation for Monthly Reactive Support and Voltage Control Settlement Debit  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 Settlement Debit | MR Ch.9 s.4.2.3 | Equation for Regulation Service 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 s*ettlement hours* ‘H’. | Monthly | Due *IESO* | 13 | N/A | 0 | 13 |  |
| 460 | IESO-Controlled Grid Special Operations Debit | MR Ch.5 s.8.2.6 | Equation for IESO-Controlled Grid Special Operations 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 s*ettlement 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 | Equation for Must Run Contract 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’. | Monthly | Due *IESO* | 13 | N/A | 0 | 13 |  |
| 600 | Network Service Credit | MR Ch.9 s.4.1 | Equation for Network Service Credit  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 | Equation for Line Connection Service Credit  Where ‘H’ is the set of all *settlement hours* ‘h’ in the month during which the Line Connection Service Demand occurs at every *delivery point* defined for Transmission Line Connection Service charges. | Monthly | Due applicable *transmitters* | 13 | N/A | N/A | N/A | Subject to the OEB “Ontario Transmission Rate Order”. |
| 602 | Transformation Connection Service Credit | MR Ch.9 s.4.1 | Equation for Transformation Connection Service Credit  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 | Equation for Export Transmission Service Credit  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 TD653 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 | Network Service Charge  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 | Line Connection Service Charge  Where ‘h’ is the *settlement hour* of the current *billing period* in which LCDk,hm denotes the non-coincident peak demand for the month*.* | Monthly | Due *IESO* | 13 | N/A | N/A | N/A | Subject to the OEB “Ontario Transmission Rate Order”. |
| 652 | Transformation Connection Service Charge | MR Ch.9 s.4.1 | Transformation Connection Service Charge  Where ‘h’ is the *settlement hour* of the current *billing period* in which TCDk,hm 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 | Export Transmission Service Charge  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. |
| 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 | Dispute Resolution Balancing Amount (IESO) | 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 | Rural and Remote Settlement Debit | 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 | MOE - Ontario Fair Hydro Plan First Nations On-reserve Delivery Balancing Amount  Where ‘K’ is the set of all *market participants* ‘k’.  Where TDk,705 is the total *settlement amount* of *charge type* 705 for the month for *market participant* ‘k’. | Monthly | Due Ministry of Energy | N/A | N/A | N/A | N/A | Eligibility, rates, and other implementation details subject to government and OEB regulations. |
| 756 | MOE - Ontario Fair Hydro Plan Distribution Rate Protection Balancing Amount | N/A | MOE - Ontario Fair Hydro Plan Distribution Rate Protection Balancing Amount  Where ‘K’ is the set of all *market participants* ‘k’.  Where TDk,706 is the total *settlement amount* of *charge type* 706 for the month for *market participant* ‘k’. | Monthly | Due Ministry of Energy | N/A | N/A | N/A | N/A | Eligibility, rates, and other implementation details subject to government and OEB regulations. |
| 850 | Market Participant 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 | Equation for GST/HST  Credit  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 | GST/HST Debit  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 | **Equation for Day-Ahead Market Energy Settlement Amount for Generators (HPTSA{1})** | Hourly | Due MP | 13 | N/A | N/A | N/A |  |
| 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*.\*\***    **Equation for Real-Time Energy Settlement Amount for Generators (HPTSA{2})** | 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 | **Equation for Day-Ahead Market Energy Settlement Amount for Dispatchable Loads HPTSA{1})** | Hourly | Due *IESO* | 13 | N/A | N/A | N/A |  |
| 1103  MRP updated | Real-Time Energy Settlement Amount for Dispatchable Loads  (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*.\*\***  Equation for Real-Time Energy Settlement Amount for Dispatchable Loads (HPTSA{2}) | Interval | Either Way | 13 | N/A | N/A | N/A |  |
| 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 | *Equation for Day-Ahead Market Energy Settlement Amount for Price Responsive Loads (HPTSA{1})*  **Where:**   1. M1 = the set of all *delivery points* ‘m’ for *price responsive loads* and *self-scheduling electricity storage resources* that are registered to withdraw; and 2. 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 | Equation for Real-Time Energy Settlement Amount for Price Responsive Loads   (HPTSA{2})  **Where:**   1. M1 = the set of all *delivery points* ‘m’ for *price responsive loads* and *self-scheduling electricity storage resources* that are registered to withdraw; and 2. 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*. | Interval | Either Way | 13 | N/A | N/A | N/A |  |
| 1106  MRP new | Day-Ahead Market Energy Settlement Amount for Virtual Transactions to Sell  (HVTSA{1}) | MR Ch.9 s.3.1.8 | Day-Ahead Market Energy Settlement Amount for Virtual Transactions to Sell | 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 | Real-Time Energy Settlement Amount for Virtual Transactions to Sell | 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 | Day-Ahead Market Energy Settlement for Virtual Transactions to Buy | Hourly | Due *IESO* | N/A | N/A | N/A | N/A |  |
| 1109  MRP new | Real-Time Energy Settlement Amount for Virtual Transactions to Buy  (HVTSA{2}) | MR Ch.9 s.3.1.9 | Real-Time Energy Settlement Amount for Virtual Transactions to Buy | 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 | Equation for Day-Ahead Market Energy Settlement Amount for Imports  (HPTSA{1}) | 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*.\*\***    **Equation for Real-Time Energy Settlement Amount for Imports  (HPTSA{2})** | Interval | Either Way | N/A | 13 | N/A | N/A |  |
| 1112  MRP new | Day-Ahead Market Energy Settlement Amount for Exports  (HPTSA{1}) | MR Ch.9 ss.3.1.2 and 3.1.3 | **Equation for Day-Ahead Market Energy Settlement Amount for Exports  (HPTSA{1})** | Hourly | Due *IESO* | N/A | N/A | 0 | 13 |  |
| 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*.\*\***  **Equation for Real-Time Energy Settlement Amount for Exports  (HPTSA{2})** | 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*.\*\***    +  **Where:**  **and where:**   * 1. M2 = the set of all *hourly demand response resources* ‘d’ that are not associated with *load equipment* registered as *price responsive loads*;   **Non-Dispatchable Load Energy Settlement Amount** | Hourly | Due *IESO* | 13 | N/A | N/A | N/A |  |
| 1116  MRP new | Internal Congestion and Loss Residual  (ICLR) | MR Ch.9 s.4.7 | Internal Congestion and Loss Residual  **Where:**  Variable definitions for equation for Internal Congestion and Loss Residual  **and where:**   1. H = the set of all *settlement hours* ‘h’ in the current *energy market billing period*’; 2. M1 = the set of all *delivery points* ‘m’ for *non-dispatchable loads*; and 3. M0 = the set of all *delivery points* ‘m’ except those for *non-dispatchable loads.* | Monthly | Either Way | 13 | N/A | N/A | N/A |  |
| 1117  MRP new | Day-Ahead Market Net External Congestion Residual  (DAM\_NECR) | MR Ch.9 s.3.8.2 | Day-Ahead Market Net External Congestion Residual  **Where:**   1. = 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 |  |
| 1118  MRP new | Real-Time External Congestion Residual Uplift  (RT\_ECRU) | MR Ch.9 ss.4.8.1-  4.8.4 | **For loads:**  **Real-Time External Congestion Residual Uplift for loads**  **For exporters:**  **Real-Time External Congestion Residual Uplift for exporters**  **Variable definitions for equationReal-Time External Congestion Residual Uplift** | 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 | **Day-Ahead Market Net Interchange Scheduling Limit Residual Uplift** | Daily | Either Way | 13 | N/A | 0 | 13 |  |
| 1120  MRP new | Real-Time Net Interchange Scheduling Limit Residual Uplift  (RT\_NISLRU) | MR Ch.9 ss.3.11 and 4.8.8 | **Real-Time Net Interchange Scheduling Limit Residual Uplift   (RT_NISLRU)** | 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 | Uk x GARB | 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 | *Fuel Cost Compensation Credit Uplift*  **Where:**   1. = 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 2. 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  (CAAP) | MR Ch.9 s.4.13.1 | *Capacity Obligation – Availability Payment  (CAAP)*  **Where:**   1. H = the set of all *settlement hours* ‘h’ within the *availability window* of all *business days* in the relevant *energy market billing period*. | Monthly | Due MP | 13 | 13 | N/A | N/A |  |
| 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*:  *Capacity Obligation – Availability Charge  (CAAC)*  **Where:**   1. H = the set of all *settlement hours* ‘h’ within the *availability window* during the relevant *trading day*; 2. 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,*  = 0; 3. 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*, = 0; 4. 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*, shall be equal to the lesser of the two *demand response energy bids*; and 5. Notwithstanding any of the foregoing, shall not exceed the 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*:  *Capacity Obligation – Availability Charge  (CAAC)*  **Where:**   1. H = the set of all *settlement hours* ‘h’ within the *availability window* during the relevant *trading day*; 2. 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’, = 0; 3. 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,*  shall be equal to the lesser of the two *energy offers*; and 4. If a *capacity storage resource* receives a non-zero *energy dispatch instruction* within the relevant *availability window,* the 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*. | Daily | Due *IESO* | 13 | 13 | N/A | N/A |  |
| 1316 | Capacity Obligation – Administration Charge  (CAADM) | MR Ch.9 s.4.13.4 | **Capacity Obligation – Administration Charge  (CAADM)**  **Where:**   1. = the *capacity obligation* availabilitypayment *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 | **Capacity Obligation – Dispatch Charge  (CADC)**  **Where:**   1. 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 | **Capacity Obligation – Capacity Charge  (CACC)**  **Where:**   1. = the *capacity obligation* availabilitypayment *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 |  |
| 1319 | Capacity Obligation – Buy-Out Charge | MR Ch.9 s.4.13.9 | buy-out charge equation  **Where:**   1. 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**  **Capacity Obligation – Dispatch Test Payment and Emergency Activation Payment**  **For *capacity obligation emergency operating state* activations**   1. For *hourly demand response resource* that is not associated with *load equipment* registered as a *price responsive load*   **Where:**   1. = the load forecast deviation adjustment for *settlement hour* ‘h’ determined in accordance with MR Ch.9 s.3.2.3. 2. For *hourly demand response resource* that is associated with *load equipment* registered as a *price responsive load*   *Capacity Obligation – Dispatch Test Payment and Emergency Activation Payment* | Hourly | Due MP | 13 | 13 | N/A | N/A |  |
| 1321 | Capacity Obligation – Capacity Import Call Failure Charge  (CACIF) | MR Ch.9 s.4.13.6 | **Capacity Obligation – Capacity Import Call Failure Charge  (CACIF)**  **Where:**   1. = the *capacity obligation* availabilitypayment *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* | N/A | 13 | N/A | N/A |  |
| 1322 | Capacity Obligation – Capacity Deficiency Charge  (CACD) | MR Ch.9 s.4.13.7 | **Capacity Obligation – Capacity Deficiency Charge  (CACD)**  **Where:**   1. 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 | *Capacity Obligation – In-Period Cleared UCAP Adjustment Charge  (CAIPA)*  **Where:**   1. = the *capacity obligation* availabilitypayment *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*;* 2. = 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; 3. H = the set of all *settlement hours* ‘h’ within the *availability window* of the relevant *energy market billing period*; and 4. 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 Charge True-up Payment  (CAACT) | MR Ch.9 s.4.13.12 | *Capacity Obligation – Availability Charge True-up Payment  (CAACT)*  **Where:**   1. = 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; 2. UCAP Adjustment = a de-rate (in %) determined in accordance with MR Ch.9 s.4.13.8; 3. = the *capacity obligation* availabilitypayment *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; 4. = 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; 5. D = the set of all *trading days* within the relevant *energy market billing period*’; 6. TM = the set of all *energy market billing periods* within the relevant *obligation period*;and 7. 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 |  |
| 1325 | Capacity Obligation – Capacity Auction Charges True-up Payment  (CACT) | MR Ch.9 s.4.13.13 | *Capacity Obligation – Capacity Auction Charges True-up Payment  (CACT)*  **Where:**   1. = 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: 2. ‘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. 3. = 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: 4. ‘P’ is the set of the *settlement amounts* applied in accordance with MR Ch.9 ss. 4.13.1 and 4.13.12. 5. 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  (CAU) | MR Ch.9 s.4.13.14 | Capacity Based Recovery Amount for Class A Loads  (CAU)  **Where:**   1. H = the set of all *settlement hours* ‘h’ in the relevant *energy market billing period*; 2. M = the set of all *delivery points* ‘m’ of *market participant* ‘k’; 3. = 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 4. ‘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 5. = 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 shall be pro-rated accordingly. | Monthly | Due *IESO* | 13 | N/A | N/A | N/A | Refer to comments under *charge type* 147 |
| 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.:**  Capacity Based Recovery Amount for Class B Loads  (CAU)  **Where:**   1. TDC,k,hm = 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; 2. TDC1350,k,hm = 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:**  **Capacity Based Recovery Amount for Class B Loads  (CAU)**  **Where:**   1. TDC,k,hm = 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. 2. TDC1350,k,hm = 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*; 3. Class B load is calculated as follows:   **Capacity Based Recovery Amount for Class B Loads  (CAU)**  **Where:**   1. H = the set of all *settlement hours* ‘h’ in the relevant *energy market billing period*. 2. M = the set of all *delivery points* ‘m’ of *market participant* ‘k’. 3. C = the set of the following *charge types* ‘c’: 1314 to 1320, 1321, 1322. | Monthly | Due *IESO* | 13 | N/A | N/A | N/A | Refer to comments under *charge type* 148 |
| 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 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 |
| 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 Settlement Amount | 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 |  |
| 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 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 |  |
| 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 Balancing  Amount | N/A | OPA Contract Adjustment Balancing  Amount | Monthly | Due IESO | 0 | N/A | N/A | N/A | Implementation details subject to 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 | Ontario Electricity Rebate Balancing Amount  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 | Renewable Energy Standard Offer Program Balancing Amount  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 | Feed-In Tariff Balancing Amount  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 | Renewable Generation Connection – Monthly Compensation Settlement Debit  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 |
| 1464 | Hydroelectric Contract Initiative Balancing Amount | N/A | Hydroelectric Contract Initiative Balancing Amount  Where ‘K’ is the set of all market participants ‘k’.  Where TDk,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 | Conservation and Demand Management – Compensation Balancing Amount  Where ‘K’ is the set of all market participants ‘k’.  Where TDk,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 | Ontario Rebate for Electricity Consumers (8% Provincial Rebate) Balancing Amount  Where ‘K’ is the set of all market participants ‘k’.  Where TDk,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 | Biomass Non-Utility Generation Contracts Balancing Amount  Where ‘K’ is the set of all market participants ‘k’.  Where TDk,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 | Energy from Waste (EFW) Contracts Balancing Amount  Where ‘K’ is the set of all market participants ‘k’.  Where TDk,1419 is the total settlement amount of charge type 1419 for the month for market participant ‘k’. | Monthly | Due IESO | 0 | N/A | N/A | N/A |  |
| 1475 | Hydroelectric Standard Offer Program Balancing Amount | N/A | Hydroelectric Standard Offer Program Balancing Amount  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 | ΣKTDk,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 | TD1429 | Monthly | Due IESO | 0 | N/A | N/A | N/A | May 1, 2025 |
| 1487 | Non-Hydro Renewables Funding Balancing Amount | N/A | TD1427 | Monthly | Due IESO | 13 | N/A | N/A | N/A | Ontario Regulation 735/20 |
| 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 | Forecasting Service Balancing Amount  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 | Dispute Resolution Balancing Amount (Market)  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  Day-Ahead Market Make-Whole Payment – Energy Component 1 for Dispatchable Generation Resources not associated with a Pseudo-Unit  Dispatchable Generation Resources that are Pseudo-Units: Combustion Turbine  Day-Ahead Market Make-Whole Payment – Energy Component 1 for the combustion turbine of  Dispatchable Generation Resources Associated with a Pseudo-Unit  Dispatchable Generation Resources that are Pseudo-Units: Steam Turbine  Day-Ahead Market Make-Whole Payment – Energy Component 1 for the steam turbine of  Dispatchable Generation Resources Associated with a Pseudo-Unit | 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 ss.3.4.13.1-3.4.13.4 | Dispatchable Generation Resources – Hydroelectric Generation Resources Not Associated with Linked Forebays  Hourly Basis Equation:  Hourly Basis Equation for Day-Ahead Market Make-Whole Payment – Energy Component 1 for Hydroelectric Generation Resources Not Associated with Linked Forebays  Per-Start Equation:  Per-Start Equation for Day-Ahead Market Make-Whole Payment – Energy Component 1 for Hydroelectric Generation Resources Not Associated with Linked Forebays  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 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 is negative and is greater than , 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 shall be determined as follows under both the Hourly Basis Equation and Per-Start Equation:  if is not equal to , or the resource does not have a forbidden region, then  otherwise:Variable definition for Day-Ahead Market Make-Whole Payment – Energy Component 1 for Dispatchable Generation Resources – Hydroelectric Generation Resources Not Associated with Linked Forebays  Where:  = the forbidden region upper limit from forbidden region set ‘f’ where = , as submitted by market participant ‘k’ for delivery point ‘m’ as daily dispatch data;  = the forbidden region lower limit from forbidden region set ‘f’ where = , as submitted by market participant ‘k’ for delivery point ‘m’ as daily dispatch data; and  f = (1…N) of the forbidden region set {, } and N is the maximum number of forbidden regions submitted by market participant ‘k’ for delivery point ‘m’ as daily dispatch data. | 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 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:  Equation for Day-Ahead Market Make-Whole Payment – Energy Component 1 for Hydroelectric Generation Resources Associated with Linked Forebays when the resource has Attained Max Starts  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 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 is negative and is greater than , 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 shall be determined as follows:  if is not equal to , or the resource does not have a forbidden region, then  otherwise:Variable definition for Equation for Day-Ahead Market Make-Whole Payment – Energy Component 1 for Hydroelectric Generation Resources Associated with Linked Forebays when the resource has Attained Max Starts  Where:  = the forbidden region upper limit from forbidden region set ‘f’ where = , as submitted by market participant ‘k’ for delivery point ‘m’ as daily dispatch data;  = the forbidden region lower limit from forbidden region set ‘f’ where = , as submitted by market participant ‘k’ for delivery point ‘m’ as daily dispatch data; and  f = (1…N) of the forbidden region set {, } and N is the maximum number of forbidden regions submitted by market participant ‘k’ for delivery point ‘m’ as daily dispatch data.  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:  Equation for Day-Ahead Market Make-Whole Payment – Energy Component 1 for Hydroelectric Generation Resources Associated with Linked Forebays when the resource has not Attained Max Starts  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 shall be determined as follows:  if is not equal to , or the resource does not have a forbidden region, then  otherwise:  Variable definition for Equation for Day-Ahead Market Make-Whole Payment – Energy Component 1 for Hydroelectric Generation Resources Associated with Linked Forebays when the resource has not Attained Max Starts  Where:  = 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;  = the forbidden region upper limit from forbidden region set ‘f’ where = , as submitted by market participant ‘k’ for delivery point ‘m’ as daily dispatch data;  = the forbidden region lower limit from forbidden region set ‘f’ where = , as submitted by market participant ‘k’ for delivery point ‘m’ as daily dispatch data; and  f = (1…N) of the forbidden region set {, } and N is the maximum number of forbidden regions submitted by market participant ‘k’ for delivery point ‘m’ as daily dispatch data. | 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.3.4.8 | Dispatchable Loads and Dispatchable Electricity Storage Resources that are Registered to Withdraw  Day-Ahead Market Make-Whole Payment – Energy Component 1 for dispatchable loads | 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  Day-Ahead Market Make-Whole Payment – Energy Component 1 for non-HDR price responsive loads | 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  Day-Ahead Market Make-Whole Payment – Energy Component 1 for physical hourly demand response price responsive loads  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 |  |
| 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  Day-Ahead Market Make-Whole Payment – Energy Component 1 for Boundary Entity Resources - Imports | 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. Day-Ahead Market Make-Whole Payment – Energy Component 1 for Boundary Entity Resources - Imports | 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  Day-Ahead Market Make-Whole Payment – 10-Minute Spinning Reserve for Dispatchable Generation Resources not associated with a Pseudo-Unit  Dispatchable Generation Resources that are Pseudo-Units: Combustion Turbine  Day-Ahead Market Make-Whole Payment – 10-Minute Spinning Reserve for the combustion turbine of Dispatchable Generation Resources associated with a Pseudo-Unit  Dispatchable Generation Resources that are Pseudo-Units: Steam Turbine  Day-Ahead Market Make-Whole Payment – 10-Minute Spinning Reserve for the steam turbine of Dispatchable Generation Resources associated with a Pseudo-Unit | Hourly | Due MP | 13 | N/A | N/A | N/A |  |
| 1801  MRP new | Day-Ahead Market Make-Whole Payment – 10-Minute Spinning Reserve  (DAM\_MWP – DAM\_COMP2)  Component 2 | MR Ch.9 ss.3.4.13.3 and  3.4.13.4 | Dispatchable Generation Resources – Hydroelectric Generation Resources Not Associated with Linked Forebays  Hourly Basis Equation:  Hourly Basis Equation for Day-Ahead Market Make-Whole Payment – 10-Minute Spinning Reserve Component 2 for Dispatchable Generation Resources – Hydroelectric Generation Resources Not Associated with Linked Forebays  Per-Start Equation:  Per-Start Equation for Day-Ahead Market Make-Whole Payment – 10-Minute Spinning Reserve Component 2 for Dispatchable Generation Resources – Hydroelectric Generation Resources Not Associated with Linked Forebays  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 | Day-Ahead Market Make-Whole Payment – 10-Minute 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:  Equation for Day-Ahead Market Make-Whole Payment – 10-Minute Spinning Reserve Component 2 for Dispatchable Generation Resources – Hydroelectric Generation Resources Associated with Linked Forebays when the resource has Attained Max Starts  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:  Equation for Day-Ahead Market Make-Whole Payment – 10-Minute Spinning Reserve Component 2 for Dispatchable Generation Resources – Hydroelectric Generation Resources Associated with Linked Forebays when the resource has not Attained Max Starts  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:  = 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. | Hourly | Due MP | 13 | N/A | N/A | N/A |  |
| 1801  MRP new | Day-Ahead Market Make-Whole Payment – 10-Minute 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  Equation for Day-Ahead Market Make-Whole Payment – 10-Minute Spinning Reserve Component 2 for Dispatchable Loads | 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.3.4.7, 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  Equation for Day-Ahead Market Make-Whole Payment – 10-Minute Spinning Reserve Component 2 for Dispatchable Generation Resources not associated with a Pseudo-Unit  Dispatchable Generation Resources that are Pseudo-Units: Combustion Turbine  Equation for Day-Ahead Market Make-Whole Payment – 10-Minute Spinning Reserve Component 2 for the combustion turbine of Dispatchable Generation Resources associated with a Pseudo-Unit  Dispatchable Generation Resources that are Pseudo-Units: Steam Turbine  Equation for Day-Ahead Market Make-Whole Payment – 10-Minute Spinning Reserve Component 2 for the steam turbine of Dispatchable Generation Resources associated with a Pseudo-Unit | 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:  Hourly Basis Equation for Day-Ahead Market Make-Whole Payment – 10-Minute Non-Spinning Reserve Component 2 for Hydroelectric Generation Resources Not Associated with Linked Forebays  Per-Start Equation:  Per-Start Equation for Day-Ahead Market Make-Whole Payment – 10-Minute Non-Spinning Reserve Component 2 for Hydroelectric Generation Resources Not Associated with Linked Forebays  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 |  |
| 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:  Equation for Day-Ahead Market Make-Whole Payment – 10-Minute Non-Spinning Reserve Component 2 for Hydroelectric Generation Resources Associated with Linked Forebays when the resource has Attained Max Starts  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:  Equation for  Day-Ahead Market Make-Whole Payment – 10-Minute Non-Spinning Reserve Component 2 for Hydroelectric Generation Resources Associated with Linked Forebays when the resource has not Attained Max Starts  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:  = 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. | 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 s.3.4.8 | Dispatchable Loads and Dispatchable Electricity Storage Resources that are Registered to Withdraw  Equation for  Day-Ahead Market Make-Whole Payment – 10-Minute Non-Spinning Reserve Component 2 for dispatchable loads | 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 s.3.4.11 | Boundary Entity Resources - Imports  Equation for  Day-Ahead Market Make-Whole Payment – 10-Minute Non-Spinning Reserve Component 2 for Boundary Entity Resources - Imports | Hourly | Due MP | N/A | 13 | 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 s.3.4.12 | Boundary Entity Resources – Exports  Equation for  Day-Ahead Market Make-Whole Payment – 10-Minute Non-Spinning Reserve Component 2 for Boundary Entity Resources - Imports | 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  Equation for Day-Ahead Market Make-Whole Payment – 30-Minute Operating Reserve Component 2 for Dispatchable Generation Resources not associated with a Pseudo-Unit  Dispatchable Generation Resources that are Pseudo-Units: Combustion Turbine  Equation for  Day-Ahead Market Make-Whole Payment – 30-Minute Operating Reserve for the combustion turbine of Dispatchable Generation Resources associated with a Pseudo-Unit  Dispatchable Generation Resources that are Pseudo-Units: Steam Turbine  Equation for  Day-Ahead Market Make-Whole Payment – 30-Minute Operating ReserveComponent 2 for the steam turbine of Dispatchable Generation Resources associated with a Pseudo-Unit | 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 ss.3.4.13.3 and  3.4.13.4 | Dispatchable Generation Resources – Hydroelectric Generation Resources Not Associated with Linked Forebays  Hourly Basis Equation:  Hourly Basis Equation for  Day-Ahead Market Make-Whole Payment – 30-Minute Operating Reserve Component 2 for Hydroelectric Generation Resources Not Associated with Linked Forebays  Per-Start Equation:  Per-Start Equation for  Day-Ahead Market Make-Whole Payment – 10-Day-Ahead Market Make-Whole Payment – 30-Minute Operating Reserve Component 2 for Hydroelectric Generation Resources Not Associated with Linked Forebays  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:  Equation for  Day-Ahead Market Make-Whole Payment – 30-Minute Operating Reserve Component 2 for Hydroelectric Generation Resources Associated with Linked Forebays when the resource has Attained Max Starts  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:  Equation for  Day-Ahead Market Make-Whole Payment – 30-Minute Operating Reserve Component 2 for Hydroelectric Generation Resources Associated with Linked Forebays when the resource has not Attained Max Starts  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:  = 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. | 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.3.4.8 | Dispatchable Loads and Dispatchable Electricity Storage Resources that are Registered to Withdraw  Equation for  Day-Ahead Market Make-Whole Payment – 30-Minute Operating Reserve Component 2 for dispatchable loads | 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.3.4.11 | Boundary Entity Resources – Imports  Equation for  Day-Ahead Market Make-Whole Payment – 30-Minute Operating Reserve Component 2 for boundary entity resources - imports | 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  Equation for  Day-Ahead Market Make-Whole Payment – 30-Minute Operating Reserve Component 2 for boundary entity resources - exports | Hourly | Due MP | N/A | N/A | 13 | 13 |  |
| 1804  MRP new | Day-Ahead Market Generator Offer Guarantee – Energy  (DAM\_GOG – DAM\_GOG\_COMP1)  Component 1 | MR Ch.9 ss.4.4.6, 4.4.15, and  4.4.22 | GOG-eligible Resources that are not Pseudo-Units  Equation for  Day-Ahead Market Generator Offer Guarantee – Energy for GOG-eligible Resources not associated with a Pseudo-Unit  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;  = 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 will be replaced with for those settlement hours in which they have such constraint.    GOG-eligible Resources that are Pseudo-Units: Combustion Turbine  Equation for  Day-Ahead Market Generator Offer Guarantee – Energy for combustion turbine of  GOG-eligible Resources associated with a Pseudo-Unit  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  = 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  Equation for  Day-Ahead Market Generator Offer Guarantee – Energy for steam turbine of  GOG-eligible Resources associated with a Pseudo-UnitWhere:  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  = 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. | Hourly | Either Way | 13 | N/A | N/A | N/A |  |
| 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  Equation for Day-Ahead Market Generator Offer Guarantee – Operating Reserve for GOG-eligible Resources not associated with a Pseudo-Unit  Where:  H = the set of settlement hours within the relevant day-ahead commitment period.  GOG-eligible Resources that are Pseudo-Units: Combustion TurbineEquation for Day-Ahead Market Generator Offer Guarantee – Operating Reserve for cobustion turbine of GOG-eligible Resources associated with a Pseudo-Unit  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  Equation for Day-Ahead Market Generator Offer Guarantee – Operating Reserve for combustion turbine of GOG-eligible Resources associated with a Pseudo-Unit  Where:  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. | Hourly | Either Way | 13 | N/A | N/A | N/A |  |
| 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  Equation for Day-Ahead Market Generator Offer Guarantee – Over Midnight for GOG-eligible Resources not associated with a Pseudo-Unit  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;  = the minimum loading point of the GOG-eligible resource for Day 0 for market participant ‘k’ for delivery point ‘m’; and  = 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  Equation for Day-Ahead Market Generator Offer Guarantee – Over Midnight for GOG-eligible Resources not associated with a Pseudo-Unit  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’;  = the minimum loading point of the combustion turbine resource associated with combustion turbine resource delivery point ‘c’; and  = 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  Day-Ahead Market Generator Offer Guarantee – Over Midnight Component 3 for GOG-eligible Resources Associated with a Pseudo-Unit: Steam Turbine  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;  = the minimum loading point of steam turbine resource associated with pseudo-unit 'p’ for market participant ‘k’; and  = 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. | Hourly | Either Way | 13 | N/A | N/A | N/A |  |
| 1807  MRP new | Day-Ahead Market Generator Offer Guarantee – Start-up  (DAM\_GOG – DAM\_GOG\_COMP4)  Component 4 | 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:  Day-Ahead Market Generator Offer Guarantee – Start-up Component 4 for GOG-eligible Resources not associated with a Pseudo-Unit  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:  Day-Ahead Market Generator Offer Guarantee – Start-up Component 4 for GOG-eligible Resources not associated with a Pseudo-Unit  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:  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:  Day-Ahead Market Generator Offer Guarantee – Start-up Component 4 for GOG-eligible Resources Associated with a Pseudo-Unit: Combustion Turbine  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:  Day-Ahead Market Generator Offer Guarantee – Start-up Component 4 for GOG-eligible Resources Associated with a Pseudo-Unit: Combustion Turbine  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:  GOG-eligible Resources that are Pseudo-Units: Steam Turbine  Day-Ahead Market Generator Offer Guarantee – Start-up Component 4 for GOG-eligible Resources Associated with a Pseudo-Unit: Steam Turbine  Where:  C = the set of all combustion turbine resource delivery points 'c’ associated with steam turbine resource delivery point ‘s’;  = 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. | Hourly | Due MP | 13 | N/A | N/A | N/A |  |
| 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  Day-Ahead Market Generator Offer Guarantee – DAM Make-Whole Payment Offset Component 5 for GOG-eligible Resources not associated with a Pseudo-Unit  Where:  H = the set of settlement hours within the relevant day-ahead commitment period.  GOG-eligible Resources that are Pseudo-Units: Combustion Turbine  Day-Ahead Market Generator Offer Guarantee – DAM Make-Whole Payment Offset Component 5 for GOG-eligible Resources Associated with a Pseudo-Unit: Combustion Turbine  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  Day-Ahead Market Generator Offer Guarantee – DAM Make-Whole Payment Offset Component 5 for GOG-eligible Resources Associated with a Pseudo-Unit: Steam Turbine  Where:  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. | Hourly | Due IESO | 13 | N/A | N/A | N/A |  |
| 1815  MRP new | Day-Ahead Market Balancing Credit - Energy  (DAM\_BCE) | MR Ch.9 s.3.3 | GOG-eligible Resources  Equation for Day-Ahead Market Balancing Credit - Energy for GOG-eligible resources  Boundary Entity Resources  for an import transaction:  Equation for Day-Ahead Market Balancing Credit - Energy for boundary entity resources for import transactions  for an export transaction:  Equation for Day-Ahead Market Balancing Credit - Energy for boundary entity resources for export transactions | 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  Equation for Day-Ahead Market Balancing Credit – Operating Reserve for GOG-eligible resources  Boundary Entity Resources  Equation for Day-Ahead Market Balancing Credit – Operating Reserve for boundary entity resources | Interval | Due MP | 13 | 13 | 13 | 13 |  |
| 1828  MRP new | Day-Ahead Market Import Failure Charge  (DAM\_IMFC) | MR Ch.9 ss.3.7A.1 and 3.7A.2 | Day-Ahead Market Import Failure Charge  (DAM_IMFC)  Where:  Day-Ahead Market Import Failure Charge | 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 | Day-Ahead Market Export Failure Charge  Where:  Day-Ahead Market Export Failure Charge | Interval | Due IESO | N/A | N/A | 0 | 13 |  |
| 1830 | Tariff Response charge for Exports | MR Ch.10 s.4.6 | -1 x | 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 | Equation for Day-Ahead Market Uplift  Where:  = 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’;  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  = calculated in accordance with MR Ch.9 s.4.14.5. | Daily | Due IESO | 13 | N/A | 0 | 13 |  |
| 1851  MRP new | 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  Equation for Day-Ahead Market Reliability Scheduling Uplift for Load Resources and Boundary Entity Resources – Export Transactions  Where:  = 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  and where :  and each component is determined as follows:  Day-Ahead Market Reliability Scheduling Uplift  and each component is determined as follows:  Day-Ahead Market Reliability Scheduling Uplift  = calculated in accordance with MR Ch.9 s.4.4. | Daily | Due IESO | 13 | N/A | 0 | 13 |  |
| 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  Day-Ahead Market Reliability Scheduling Uplift – Virtual Transactions to Sell  Where:  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 | Equation for Day-Ahead Market Balancing Credit  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 Balancing Amount | MR Ch.10 s.4.6 | -1 x | Hourly | Due IESO | N/A | N/A | 0 | N/A | Ontario Regulation 25/25 |
| 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  Real-Time Make-Whole Payment – Lost Cost for Energy  Where:  the disptachable generation resource is registered as a hydroelectric generation resource, is greater than , and is less than or equal to , then  Real-Time Make-Whole Payment – Lost Cost for Energy  Where:  = the forbidden region upper limit from forbidden region set ‘f’ where <= , as submitted by market participant ‘k’ for delivery point ‘m’ as daily dispatch data;  = the forbidden region lower limit from forbidden region set ‘f’ where > , as submitted by market participant ‘k’ for delivery point ‘m’ as daily dispatch data; and  f = (1…N) of the forbidden region set {, } and N is the maximum number of forbidden regions submitted by market participant ‘k’ for delivery point ‘m’ as daily dispatch data.  Otherwise shall equal zero.  Dispatchable Generation Resources that are Pseudo-Units: Combustion Turbine  Equation for Real-Time Make-Whole Payment for Dispatchable Generation Resources Associated with a Pseudo-Unit: Combustion Turbine  Dispatchable Generation Resources that are Pseudo-Units: Steam Turbine  Equation for Real-Time Make-Whole Payment for Dispatchable Generation Resources Associated with a Pseudo-Unit: Steam Turbine | 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.3.5.7 | Dispatchable Loads and Dispatchable Electricity Storage Resources that are Registered to Withdraw  Real-Time Make-Whole Payment – Lost Cost for Energy for dispatchable loads | 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:  Real-Time Make-Whole Payment – Lost Cost for Energy for boundary entity resources exports with a manual dispatch out of merit  Export transaction dispatched with a reason code associated with a pre-dispatch pricing discrepancy:  Real-Time Make-Whole Payment – Lost Cost for Energy for boundary entity resources exports with a pre-dispatch pricing discrepancy | Interval | Due MP | N/A | N/A | 13 | 13 |  |
| 1901  MRP new | Real-Time Make-Whole Payment – Lost Cost for 10-Minute Spinning 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  Real-Time Make-Whole Payment – Lost Cost for 10-Minute Spinning Reserve for Dispatchable Generation Resources not associated with a Pseudo-Unit  Dispatchable Generation Resources that are Pseudo-Units: Combustion Turbine  Real-Time Make-Whole Payment – Lost Cost for 10-Minute Spinning Reserve for Dispatchable Generation Resources Associated with a Pseudo-Unit: Combustion Turbine  Dispatchable Generation Resources that are Pseudo-Units: Steam Turbine  Real-Time Make-Whole Payment – Lost Cost for 10-Minute Spinning Reserve for Dispatchable Generation Resources Associated with a Pseudo-Unit: Steam Turbine | Interval | Due MP | 13 | N/A | N/A | N/A |  |
| 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  Real-Time Make-Whole Payment – Lost Cost for 10-Minute Spinning Reserve | 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 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  Real-Time Make-Whole Payment – Lost Cost for 10-Minute Non-Spinning Reserve for Dispatchable Generation Resources not associated with a Pseudo-Unit  Dispatchable Generation Resources that are Pseudo-Units: Combustion Turbine  Real-Time Make-Whole Payment – Lost Cost for 10-Minute Non-Spinning Reserve for Dispatchable Generation Resources Associated with a Pseudo-Unit: Combustion Turbine  Dispatchable Generation Resources that are Pseudo-Units: Steam Turbine  Real-Time Make-Whole Payment – Lost Cost for 10-Minute Non-Spinning Reserve for Dispatchable Generation Resources Associated with a Pseudo-Unit: Steam Turbine | 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.3.5.7 | Dispatchable Loads and Dispatchable Electricity Storage Resources that are Registered to Withdraw  Real-Time Make-Whole Payment – Lost Cost for 10-Minute Non-Spinning Reserve for dispatchable loads | 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:  Real-Time Make-Whole Payment – Lost Cost for 10-Minute Non-Spinning Reserve for Export transaction dispatched with a reason code associated with manual dispatch out-of-merit:  Export transaction dispatched with a reason code associated with a pre-dispatch pricing discrepancy:  Real-Time Make-Whole Payment – Lost Cost for 10-Minute Non-Spinning Reserve for Export transaction dispatched with a reason code associated with a pre-dispatch pricing discrepancy: | Interval | Due MP | N/A | N/A | 13 | 13 |  |
| 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  Real-Time Make-Whole Payment – Lost Cost for 10-Minute Non-Spinning Reserve Boundary Entity Resources – Imports | 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  Real-Time Make-Whole Payment – Lost Cost for 30-Minute Operating Reserve Dispatchable Generation Resources not associated with a Pseudo-Unit  Dispatchable Generation Resources that are Pseudo-Units: Combustion Turbine  Real-Time Make-Whole Payment – Lost Cost for 30-Minute Operating Reserve Dispatchable Generation Resources Associated with a Pseudo-Unit: Combustion Turbine  Dispatchable Generation Resources that are Pseudo-Units: Steam Turbine  Real-Time Make-Whole Payment – Lost Cost for 30-Minute Operating Reserve Dispatchable Generation Resources Associated with a Pseudo-Unit: Steam Turbine | Interval | Due MP | 13 | N/A | 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 s.3.5.7 | Dispatchable Loads and Dispatchable Electricity Storage Resources that are Registered to Withdraw  Real-Time Make-Whole Payment – Lost Cost for 30-Minute Operating Reserve for Dispatchable Loads | Interval | Due MP | 13 | N/A | 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 s.3.5.8 | Boundary Entity Resources – Exports  Export transaction dispatched with a reason code associated with manual dispatch out-of-merit:  Real-Time Make-Whole Payment – Lost Cost for 30-Minute Operating Reserve for Export transaction dispatched with a reason code associated with manual dispatch out-of-merit:  Export transaction dispatched with a reason code associated with a pre-dispatch pricing discrepancy:  Real-Time Make-Whole Payment – Lost Cost for 30-Minute Operating Reserve for Export transaction dispatched with a reason code associated with a pre-dispatch pricing discrepancy | 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  Real-Time Make-Whole Payment – Lost Cost for 30-Minute Operating Reserve Boundary Entity Resources - Imports | Interval | Due MP | N/A | 13 | N/A | N/A |  |
| 1904  MRP new | Real-Time Make-Whole Payment – Lost Opportunity Cost for Energy  (RT\_MWP – RT\_ELOC) | 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 InjectReal-Time Make-Whole Payment – Lost Opportunity Cost for Energy for Dispatchable Generation Resources not associated with a Pseudo-Unit  Where:  if the dispatchable generation resource is registered as a hydroelectric generation resource, is greater than , and is less than or equal to , then  Real-Time Make-Whole Payment – Lost Opportunity Cost for Energy  Where:  ‘’ = the forbidden region upper limit from forbidden region set ‘f’ where < , as submitted by market participant ‘k’ for delivery point ‘m’ as daily dispatch data;  ‘’ = the forbidden region lower limit from forbidden region set ‘f’ where >= , as submitted by market participant ‘k’ for delivery point ‘m’ as daily dispatch data; and  ‘f’ = (1…N) of the forbidden region set {, } and N is the maximum number of forbidden regions submitted by market participant ‘k’ for delivery point ‘m’ as daily dispatch data.  Otherwise shall equal zero.  Dispatchable Generation Resources that are Pseudo-Units: Combustion Turbine  Real-Time Make-Whole Payment – Lost Opportunity Cost for Energy for Dispatchable Generation Resources Associated with a Pseudo-Unit: Combustion Turbine  Dispatchable Generation Resources that are Pseudo-Units: Steam Turbine  Real-Time Make-Whole Payment – Lost Opportunity Cost for Energy for Dispatchable Generation Resources Associated with a Pseudo-Unit: Steam Turbine  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  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. | Interval | Due MP | 13 | N/A | N/A | N/A |  |
| 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  Real-Time Make-Whole Payment – Lost Opportunity Cost for Energy for dispatchable loads | 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  Real-Time Make-Whole Payment – Lost Opportunity Cost for 10-Minute Spinning Reserve for Dispatchable Generation Resources not associated with a Pseudo-Unit  Dispatchable Generation Resources that are Pseudo-Units: Combustion TurbineReal-Time Make-Whole Payment – Lost Opportunity Cost for 10-Minute Spinning Reserve for Dispatchable Generation Resources Associated with a Pseudo-Unit: Combustion Turbine  Dispatchable Generation Resources that are Pseudo-Units: Steam Turbine  Real-Time Make-Whole Payment – Lost Opportunity Cost for 10-Minute Spinning Reserve for Dispatchable Generation Resources Associated with a Pseudo-Unit: Steam Turbine | 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 s.3.5.7 | Dispatchable Loads and Dispatchable Electricity Storage Resources that are Registered to Withdraw  Real-Time Make-Whole Payment – Lost Opportunity Cost for 10-Minute Spinning Reserve for Dispatchable Loads | 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  Real-Time Make-Whole Payment – Lost Opportunity Cost for 10-Minute Non-Spinning Reserve Dispatchable Generation Resources not associated with a Pseudo-Unit  Dispatchable Generation Resources that are Pseudo-Units: Combustion Turbine  Real-Time Make-Whole Payment – Lost Opportunity Cost for 10-Minute Non-Spinning Reserve Dispatchable Generation Resources Associated with a Pseudo-Unit: Combustion Turbine  Dispatchable Generation Resources that are Pseudo-Units: Steam Turbine  Real-Time Make-Whole Payment – Lost Opportunity Cost for 10-Minute Non-Spinning Reserve Dispatchable Generation Resources Associated with a Pseudo-Unit: Steam Turbine | 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 s.3.5.7 | Dispatchable Loads and Dispatchable Electricity Storage Resources that are Registered to Withdraw  Real-Time Make-Whole Payment – Lost Opportunity Cost for 10-Minute Non-Spinning Reserve for Dispatchable Loads | 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  Real-Time Make-Whole Payment – Lost Opportunity Cost for 30-Minute Operating Reserve for Dispatchable Generation Resources not associated with a Pseudo-Unit  Dispatchable Generation Resources that are Pseudo-Units: Combustion Turbine  Real-Time Make-Whole Payment – Lost Opportunity Cost for 30-Minute Operating Reserve for Dispatchable Generation Resources Associated with a Pseudo-Unit: Combustion Turbine  Dispatchable Generation Resources that are Pseudo-Units: Steam Turbine  Real-Time Make-Whole Payment – Lost Opportunity Cost for 30-Minute Operating Reserve for Dispatchable Generation Resources Associated with a Pseudo-Unit: Steam Turbine | 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 s.3.5.7 | Dispatchable Loads and Dispatchable Electricity Storage Resources that are Registered to Withdraw  Real-Time Make-Whole Payment – Lost Opportunity Cost for 30-Minute Operating Reserve for Dispatchable Loads | Interval | Due MP | 13 | N/A | N/A | N/A |  |
| 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  Real-Time Make-Whole Payment - Operating Reserve Non-Accessibility Lost Cost Reversal  Real-Time Make-Whole Payment -  Operating Reserve Non-Accessibility Lost Cost Reversal   (RT_OLCRC)  Real-Time Make-Whole Payment -  Operating Reserve Non-Accessibility Lost Cost Reversal   (RT_OLCRC)  Real-Time Make-Whole Payment -  Operating Reserve Non-Accessibility Lost Cost Reversal   (RT_OLCRC)  Dispatchable Generation Resources that are Pseudo-Units  Combustion turbine resource:  Real-Time Make-Whole Payment - Operating Reserve Non-Accessibility Lost Cost Reversal  Where:  Real-Time Make-Whole Payment - Operating Reserve Non-Accessibility Lost Cost Reversal  Real-Time Make-Whole Payment - Operating Reserve Non-Accessibility Lost Cost Reversal  Real-Time Make-Whole Payment - Operating Reserve Non-Accessibility Lost Cost Reversal  Steam turbine resource:  Real-Time Make-Whole Payment - Operating Reserve Non-Accessibility Lost Cost Reversal  Where:  For synchronized ten-minute operating reserve:  if and if  then:  Real-Time Make-Whole Payment - Operating Reserve Non-Accessibility Lost Cost Reversal  otherwise,  For non-synchronized ten-minute operating reserve:  if and if , then:  Real-Time Make-Whole Payment - Operating Reserve Non-Accessibility Lost Cost Reversal  otherwise,  For thirty-minute operating reserve:  if and if  , then:  Real-Time Make-Whole Payment - Operating Reserve Non-Accessibility Lost Cost Reversal  otherwise, | Interval | Due IESO | 13 | N/A | N/A | N/A |  |
| 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  Real-Time Make-Whole Payment - Operating Reserve Non-Accessibility Lost Opportunity Cost Reversal  Where:  1909 MRP new Real-Time Make-Whole Payment - Operating Reserve Non-Accessibility Lost Opportunity Cost Reversal  (RT_OLOCRC)  1909 MRP new Real-Time Make-Whole Payment - Operating Reserve Non-Accessibility Lost Opportunity Cost Reversal  (RT_OLOCRC)  1909 MRP new Real-Time Make-Whole Payment - Operating Reserve Non-Accessibility Lost Opportunity Cost Reversal  (RT_OLOCRC)  Dispatchable Generation Resources that are Pseudo-Units  Combustion turbine resource:  1909 MRP new Real-Time Make-Whole Payment - Operating Reserve Non-Accessibility Lost Opportunity Cost Reversal  (RT_OLOCRC)  Where:  1909 MRP new Real-Time Make-Whole Payment - Operating Reserve Non-Accessibility Lost Opportunity Cost Reversal  (RT_OLOCRC)  1909 MRP new Real-Time Make-Whole Payment - Operating Reserve Non-Accessibility Lost Opportunity Cost Reversal  (RT_OLOCRC)  1909 MRP new Real-Time Make-Whole Payment - Operating Reserve Non-Accessibility Lost Opportunity Cost Reversal  (RT_OLOCRC)  Steam turbine resource:  1909 MRP new Real-Time Make-Whole Payment - Operating Reserve Non-Accessibility Lost Opportunity Cost Reversal  (RT_OLOCRC)  Where:  1909 MRP new Real-Time Make-Whole Payment - Operating Reserve Non-Accessibility Lost Opportunity Cost Reversal  (RT_OLOCRC)  1909 MRP new Real-Time Make-Whole Payment - Operating Reserve Non-Accessibility Lost Opportunity Cost Reversal  (RT_OLOCRC)  1909 MRP new Real-Time Make-Whole Payment - Operating Reserve Non-Accessibility Lost Opportunity Cost Reversal  (RT_OLOCRC) | Interval | Due IESO | 13 | N/A | N/A | N/A |  |
| 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  Real-Time Generator Offer Guarantee – Energy Component 1 for GOG-eligible Resources not associated with a Pseudo-Unit  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 will be replaced with for those metering intervals in which they have such constraint.  GOG-eligible Resources that are Pseudo-Units: Combustion Turbine  Real-Time Generator Offer Guarantee – Energy for GOG-eligible Resources Associated with a Pseudo-Unit: Combustion Turbine  (RT_GOG)  Component 1  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  Real-Time Generator Offer Guarantee – Energy Component 1 for GOG-eligible Resources Associated with a Pseudo-Unit: Steam Turbine  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 less than its 1-on-1 minimum loading point; and (ii) none of the associated pseudo-units have a day-ahead schedule. | Interval | Either Way | 13 | N/A | N/A | N/A |  |
| 1911  MRP new | Real-Time Generator Offer Guarantee – Operating Reserve  (RT\_GOG – RT\_GOG\_COMP2)  Component 2 | MR Ch.9 ss. 4.5.7, 4.5.16, and 4.5.23 | GOG-eligible Resources that are not Pseudo-Units  Real-Time Generator Offer Guarantee – Operating Reserve for Real-Time Generator Offer Guarantee – Operating Reserve for GOG-eligible Resources not associated with a Pseudo-Unit  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  Real-Time Generator Offer Guarantee – Operating Reserve  (RT_GOG)  Component 2  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  Real-Time Generator Offer Guarantee – Operating Reserve for Real-Time Generator Offer Guarantee – Operating Reserve for GOG-eligible Resources Associated with a Pseudo-Unit: Steam Turbine  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 |  |
| 1912  MRP new | Real-Time Generator Offer Guarantee – Over Midnight  (RT\_GOG – RT\_GOG\_COMP3)  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  Real-Time Generator Offer Guarantee – Over Midnight for GOG-eligible Resources not associated with a Pseudo-Unit  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  = 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  Real-Time Generator Offer Guarantee – Over Midnight for GOG-eligible Resources not associated with a Pseudo-Unit  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;  = 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’.  GOG-eligible Resources that are Pseudo-Units: Steam Turbine  Real-Time Generator Offer Guarantee – Over Midnight for GOG-eligible Resources Associated with a Pseudo-Unit: Steam Turbine  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  = the minimum loading point of pseudo-unit 'p’ for market participant ‘k’ for Day 1. | Interval | Either Way | 13 | N/A | N/A | N/A |  |
| 1913  MRP new | Real-Time Generator Offer Guarantee – Start-up  (RT\_GOG – RT\_GOG\_COMP4)  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:  Real-Time Generator Offer Guarantee – Start-up for Real-Time Generator Offer Guarantee – Start-up for GOG-eligible Resources not associated with a Pseudo-Unit  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:  Real-Time Generator Offer Guarantee – Start-up for Real-Time Generator Offer Guarantee – Start-up for GOG-eligible Resources not associated with a Pseudo-Unit  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:  In determining , 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:  Real-Time Generator Offer Guarantee – Start-up for Real-Time Generator Offer Guarantee – Start-up for GOG-eligible Resources not associated with a Pseudo-Unit  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:  Real-Time Generator Offer Guarantee – Start-up for Real-Time Generator Offer Guarantee – Start-up for GOG-eligible Resources not associated with a Pseudo-Unit  otherwise,  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:  Real-Time Generator Offer Guarantee – Start-up for Real-Time Generator Offer Guarantee – Start-up for GOG-eligible Resources Associated with a Pseudo-Unit: Combustion Turbine  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:  Real-Time Generator Offer Guarantee – Start-up for Real-Time Generator Offer Guarantee – Start-up for GOG-eligible Resources Associated with a Pseudo-Unit: Combustion Turbine  Where: = the number of metering intervals after the first six metering intervals that the combustion turbine resource took to achieve its minimum loading point.  otherwise,  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:  Real-Time Generator Offer Guarantee – Start-up for Real-Time Generator Offer Guarantee – Start-up for GOG-eligible Resources Associated with a Pseudo-Unit: Combustion Turbine  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:  Real-Time Generator Offer Guarantee – Start-up for Real-Time Generator Offer Guarantee – Start-up for GOG-eligible Resources Associated with a Pseudo-Unit: Combustion Turbine  Where: = the number of metering intervals after the first six metering intervals that the combustion turbine resource took to achieve its minimum loading point.  otherwise,  GOG-eligible Resources that are Pseudo-Units: Steam Turbine  Real-Time Generator Offer Guarantee – Start-up for Real-Time Generator Offer Guarantee – Start-up for GOG-eligible Resources Associated with a Pseudo-Unit: Steam Turbine  Where:  C = the set of all combustion turbine resource delivery points 'c’ associated with steam turbine resource delivery point ‘s’;  = 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. | Interval | Due MP | 13 | N/A | N/A | N/A |  |
| 1914  MRP new | Real-Time Generator Offer Guarantee – RT Make-Whole Payment Offset  (RT\_GOG – RT\_GOG\_COMP5)  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  Real-Time Generator Offer Guarantee – RT Make-Whole Payment Offset Component 5 for GOG-eligible Resources not associated with a Pseudo-Unit  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  Real-Time Generator Offer Guarantee – RT Make-Whole Payment Offset Component 5 for GOG-eligible Resources Associated with a Pseudo-Unit: Combustion Turbine  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  Real-Time Generator Offer Guarantee – RT Make-Whole Payment Offset Component 5 for GOG-eligible Resources Associated with a Pseudo-Unit: Steam Turbine  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 | Due IESO | 13 | N/A | N/A | N/A |  |
| 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  Real-Time Generator Offer Guarantee – Operating Reserve Non-Accessibility Reversal (RT_GOG - RT_GOG_CB)  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;  = 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;  = (-1) x  and are calculated as follows:  For synchronized ten-minute operating reserve  if , then  Real-Time Generator Offer Guarantee – Operating Reserve Non-Accessibility Reversal (RT_GOG - RT_GOG_CB)  otherwise, and  For non-synchronized ten-minute operating reserve  if , then  Real-Time Generator Offer Guarantee – Operating Reserve Non-Accessibility Reversal (RT_GOG - RT_GOG_CB)  otherwise, and  For thirty-minute operating reserve  if , then  Real-Time Generator Offer Guarantee – Operating Reserve Non-Accessibility Reversal (RT_GOG - RT_GOG_CB)  Real-Time Generator Offer Guarantee – Operating Reserve Non-Accessibility Reversal (RT_GOG - RT_GOG_CB)  otherwise, and  GOG-eligible Resources that are Pseudo-Units  Combustion turbine resource:  Real-Time Generator Offer Guarantee – Operating Reserve Non-Accessibility Reversal (RT_GOG - RT_GOG_CB)  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;  = 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;  = (-1) x  and are calculated as follows:  For synchronized ten-minute operating reserve  if , then  Real-Time Generator Offer Guarantee – Operating Reserve Non-Accessibility Reversal (RT_GOG - RT_GOG_CB)  otherwise and  For non-synchronized ten-minute operating reserve  if , then  Real-Time Generator Offer Guarantee – Operating Reserve Non-Accessibility Reversal (RT_GOG - RT_GOG_CB)  otherwise and  For thirty-minute operating reserve  if , then  Real-Time Generator Offer Guarantee – Operating Reserve Non-Accessibility Reversal (RT_GOG - RT_GOG_CB)  otherwise and  Steam turbine resource:  Real-Time Generator Offer Guarantee – Operating Reserve Non-Accessibility Reversal (RT_GOG - RT_GOG_CB)  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;  = 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;  and are calculated as follows:  Real-Time Generator Offer Guarantee – Operating Reserve Non-Accessibility Reversal (RT_GOG - RT_GOG_CB)  Real-Time Generator Offer Guarantee – Operating Reserve Non-Accessibility Reversal (RT_GOG - RT_GOG_CB)  Real-Time Generator Offer Guarantee – Operating Reserve Non-Accessibility Reversal (RT_GOG - RT_GOG_CB) | Interval | Due IESO | 13 | N/A | N/A | N/A |  |
| 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:  Real-Time Ramp-Down Settlement Amount for GOG-eligible Resources not associated with a Pseudo-Unit  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:  Real-Time Generator Offer Guarantee – RT Make-Whole Payment Offset Component 5 for GOG-eligible Resources Associated with a Pseudo-Unit: Combustion Turbine  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  = 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:  Real-Time Ramp-Down Settlement Amount for OG-eligible Resources Associated with a Pseudo-Unit: Combustion Turbine  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:  Real-Time Ramp-Down Settlement Amount for GOG-eligible Resources Associated with a Pseudo-Unit: Combustion Turbine  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  = 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:  Real-Time Ramp-Down Settlement Amount for GOG-eligible Resources Associated with a Pseudo-Unit: Steam Turbine  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:  Real-Time Ramp-Down Settlement Amount for GOG-eligible Resources Associated with a Pseudo-Unit: Steam Turbine  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  = 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. | Interval | Due MP | 13 | N/A | N/A | N/A |  |
| 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:  Generator Failure Charge – Market Price Component for GOG-eligible Resources not associated with a Pseudo-Unit  if the market participant provides four hours or greater advance notice of a given generator failure:  Generator Failure Charge – Market Price Component for GOG-eligible Resources not associated with a Pseudo-Unit  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 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:  Generator Failure Charge – Market Price Component for GOG-eligible Resources associated with a Pseudo-Unit: Combustion Turbine  if the market participant provides four hours or greater advance notice of a given generator failure:  Generator Failure Charge – Market Price Component for GOG-eligible Resources associated with a Pseudo-Unit: Combustion Turbine  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  Generator Failure Charge – Market Price Component for GOG-eligible Resources associated with a Pseudo-Unit: Steam Turbine  if the market participant provides less than four hours of advance notice of a given generator failure or fails to provide such notice:  Generator Failure Charge – Market Price Component for GOG-eligible Resources associated with a Pseudo-Unit: Steam Turbine  if the market participant provides four hours or greater advance notice of a given generator failure:  Generator Failure Charge – Market Price Component for GOG-eligible Resources associated with a Pseudo-Unit: Steam Turbine  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’. | Interval | Due IESO | 13 | N/A | N/A | N/A |  |
| 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  Generator Failure Charge – Guarantee Cost Component for GOG-eligible Resources not associated with a Pseudo-Unit  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:  Generator Failure Charge – Guarantee Cost Component for GOG-eligible Resources not associated with a Pseudo-Unit  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  Generator Failure Charge – Guarantee Cost Component for GOG-eligible Resources not associated with a Pseudo-Unit  if the pre-dispatch operational commitment violated by the generator failure ‘f’:  is an extended pre-dispatch operational commitment, then  otherwise,  = prorating factor for market participant ‘k’ at delivery point ‘m’ for generator failure ‘f’, and calculated as:  Generator Failure Charge – Guarantee Cost Component   (GFC_GCC) - Conditions  Where:  = 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  = 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  Generator Failure Charge – Guarantee Cost Component for GOG-eligible Resources Associated with a Pseudo-Unit: Combustion Turbine  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:  Generator Failure Charge – Guarantee Cost Component for GOG-eligible Resources Associated with a Pseudo-Unit: Combustion Turbine  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:  Generator Failure Charge – Guarantee Cost Component for GOG-eligible Resources Associated with a Pseudo-Unit: Combustion Turbine  if the pre-dispatch operational commitment violated by the generator failure ‘f’:  Generator Failure Charge – Guarantee Cost Component   (GFC_GCC) - Conditions  = prorating factor for market participant ‘k’ at combustion turbine resource delivery point ‘c’ for generator failure ‘f’, and calculated as:  Generator Failure Charge – Guarantee Cost Component   (GFC_GCC) - Conditions  Where:  = 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  = 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  Generator Failure Charge – Guarantee Cost Component for GOG-eligible Resources Associated with a Pseudo-Unit: Steam Turbine  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:  Generator Failure Charge – Guarantee Cost Component for GOG-eligible Resources Associated with a Pseudo-Unit: Steam Turbine  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:  Generator Failure Charge – Guarantee Cost Component for GOG-eligible Resources Associated with a Pseudo-Unit: Steam Turbine  if the pre-dispatch operational commitment violated by the generator failure ‘f’:  is an extended pre-dispatch operational commitment, then  otherwise,  = prorating factor for market participant ‘k’ at combustion turbine resource delivery point ‘c’ for generator failure ‘f’, and calculated as:  Generator Failure Charge – Guarantee Cost Component   (GFC_GCC) - Conditions  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’;  F = the set of all combustion turbine resource or steam turbine resource failures ‘f’ occurring during the period ‘T1’;  = 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  = 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’. | Hourly | Due IESO | 13 | N/A | N/A | N/A |  |
| 1927  MRP new | Real-Time Intertie Offer Guarantee  (RT\_IOG) | MR Ch.9 s.3.6 | Real-Time Intertie Offer Guarantee  Where:  = 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:  Variable definitions for equation for Real-Time Intertie Offer Guarantee  Variable definitions for equation for Real-Time Intertie Offer Guarantee  Variable definitions for equation for Real-Time Intertie Offer Guarantee | Hourly | Due MP | N/A | 13 | N/A | N/A |  |
| 1928  MRP new | Real-Time Import Failure Charge  (RT\_IMFC) | MR Ch.9 ss.3.7.1-3.7.4 | Real-Time Import Failure Charge  (RT_IMFC)  Where:  Real-Time Import Failure Charge  (RT_IMFC) | 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 | Real-Time Export Failure Charge  (RT_EXFC)  Where:  Real-Time Export Failure Charge  (RT_EXFC) | 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 | Day-Ahead Market Reference Level Settlement Charge  (DAM_RLSC)  Where:  = the price component Pn of N-by-2 matrix of price-quantity pairs where ‘n’ is the highest indexed row of the matrix such that . | Hourly | Due IESO | 13 | N/A | N/A | N/A |  |
| 1931  MRP new | Real-Time Reference Level Settlement Charge  (RT\_RLSC) | MR Ch.9 s.5.3 | Real-Time Reference Level Settlement Charge  (RT_RLSC)  Where:  = the price component Pn of N-by-2 matrix of price-quantity pairs where ‘n’ is the highest indexed row of the matrix such that . | Hourly | Due IESO | 13 | N/A | N/A | N/A |  |
| 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.  Mitigation Amount for Physical Withholding – Energy  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;  = 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  Mitigation Amount for Physical Withholding – Energy  (EXP_PWSC)  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  = 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.  Mitigation Amount for Physical Withholding – Energy  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  = 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. | Daily | Due IESO | 13 | N/A | N/A | N/A |  |
| 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.  Mitigation Amount for Physical Withholding – 10S Operating Reserve  (EXP_PWSC – PW_OR)  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;  = 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;  Mitigation Amount for Physical Withholding – 10R Operating Reserve  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  = 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.  Mitigation Amount for Physical Withholding – 10R Operating Reserve  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  = 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. | Daily | Due IESO | 13 | N/A | N/A | N/A |  |
| 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.  Mitigation Amount for Physical Withholding – 10N Operating Reserve  (EXP_PWSC –PW_OR)  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;  = 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;  Mitigation Amount for Physical Withholding – 10N Operating Reserve  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  = 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  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.  Mitigation Amount for Physical Withholding – 10N Operating Reserve  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  = 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. | Daily | Due IESO | 13 | N/A | N/A | N/A |  |
| 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.  Mitigation Amount for Physical Withholding – 30R Operating Reserve  (EXP_PWSC – PW_OR)  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;  = 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;  Mitigation Amount for Physical Withholding – 30R Operating Reserve  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  = 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.  Mitigation Amount for Physical Withholding – 30R Operating Reserve  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  = 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. | Daily | Due IESO | 13 | N/A | N/A | N/A |  |
| 1936  MRP new | Mitigation Amount for Intertie Economic Withholding – Energy  (EXP\_EWSC – EW\_E) | 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.  Mitigation Amount for Intertie Economic Withholding – Energy  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;  Mitigation Amount for Intertie Economic Withholding – Energy  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  = 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.  Mitigation Amount for Intertie Economic Withholding – Energy  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  = 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. | Daily | Due IESO | N/A | 13 | 0 | 13 |  |
| 1937  MRP new | Mitigation Amount for Intertie Economic Withholding – 10N Operating Reserve  (EXP\_EWSC –EW\_OR) | 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.  Mitigation Amount for Intertie Economic Withholding – 10N Operating Reserve  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;  Mitigation Amount for Intertie Economic Withholding – 10N Operating Reserve  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  = 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.  Mitigation Amount for Intertie Economic Withholding – 10N Operating Reserve  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  = 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. | Daily | Due IESO | N/A | 13 | 0 | 13 |  |
| 1938  MRP new | Mitigation Amount for Intertie Economic Withholding – 30R Operating Reserve  (EXP\_EWSC – EW\_OR) | 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.  Mitigation Amount for Intertie Economic Withholding – 30R Operating Reserve  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;  Mitigation Amount for Intertie Economic Withholding – 30R Operating Reserve  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  = 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.  Mitigation Amount for Intertie Economic Withholding – 30R Operating Reserve  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  = 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. | Daily | Due IESO | N/A | 13 | 0 | 13 |  |
| 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.  Mitigation Amount for Intertie Economic Withholding – Make-Whole Payment  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;  = 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;  = 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  = 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 Amount (Market) | 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 |  |
| 1950  MRP new | Real-Time Make-Whole Payment Uplift  (RT\_MWPU) | MR Ch.9 s.3.11 | Real-Time Make-Whole Payment Uplift  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 | Real-Time Generator Offer Guarantee Uplift  (RT_GOGU)  Where:  = 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  = 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 | Real-Time Ramp-Down Settlement Amount Uplift  Where:  = 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 Component Uplift  (GFC\_MPCU) | MR Ch.9 s.3.11 | Generator Failure Charge – Market Price Component Uplift  Where:  C = the set of all charge types ‘c’ as follows: 1920. | Hourly | Due MP | 13 | N/A | 0 | 13 |  |
| 1971  MRP new | Generator Failure Charge – Guarantee Cost Component Uplift  (GFC\_GCCU) | MR Ch.9 s.4.14.1 | Generator Failure Charge – Guarantee Cost Component  Where:  = 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 | Real-Time Intertie Offer Guarantee Uplift  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 | Day-Ahead Market Reference Level Settlement Charge Uplift  Where:  C = the set of all charge types ‘c’ as follows: 1930. | Hourly | Due MP | 13 | N/A | 0 | 13 |  |
| 1981  MRP new | Real-Time Reference Level Settlement Charge Uplift  (RT\_RLSCU) | MR Ch.9 s.3.11 | Real-Time Reference Level Settlement Charge Uplift  Where:  C = the set of all charge types ‘c’ as follows: 1931. | Hourly | Due MP | 13 | N/A | 0 | 13 |  |
| 1982  MRP new | Mitigation Amount for Physical Withholding Uplift  (EXP\_PWSU) | MR Ch.9 s.4.14.9 | Mitigation Amount for Physical Withholding Uplift  Where:  = 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 | Mitigation Amount for Intertie Economic Withholding Uplift  (EXP\_EWSCU) | MR Ch.9 s.4.14.10 | Mitigation Amount for Intertie Economic Withholding Uplift  Where:  = 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 |  |
| 2470 | MOE - Ontario Electricity Support Program Balancing Amount | N/A | MOE - Ontario Electricity Support Program Balancing Amount    Where ‘K’ is the set of all market participants ‘k’.  Where TDk,1420 is the settlement amount of charge type 1420 for the month for market participant ‘k’. | Monthly | Due Ministry of Energy | 0 | N/A | N/A | N/A | Implementation details subject to government and OEB regulations. |
| 9920 | Adjustment Account Credit  (AAC) | MR Ch.9 s.6.20.5.3 | Adjustment Account Credit  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 Settlement Amount | N/A | Manual entry based on:  (1) the values submitted via on-line settlement forms “Ontario Electricity Rebate (OER) – LDC & USMP”;  and  (2) 33.2 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 and 364/16 |
| 9984 | COVID-19 Energy Assistance Program (CEAP) Balancing Amount | N/A | COVID-19 Energy Assistance Program (CEAP) Balancing Amount    Where ‘K’ is the set of all market participants ‘k’.  Where TDk,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 | IESO Administration Charge  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 |  |

### Rounding Conventions – by Charge Type

#### 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](https://www.ieso.ca/-/media/Files/IESO/Document-Library/Market-Rules-and-Manuals-Library/market-manuals/settlements/se-StatementAndDataFileFormatSpec.ashx) document. This document is located on the [Technical Interfaces](https://www.ieso.ca/en/Sector-Participants/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_Types_and). |
| **Charge Type Name** | The name of each of the *charge types*. |
| INPUT VARIABLES  **Least number of significant digits to the right of the decimal** | In terms of assessing the accuracy of the final *settlement amount*, this column is derived from the *settlement* variable received by the *settlement* system with the LEAST number of significant digits to the right of the decimal place. |
| INPUT VARIABLES  **Maximum number of significant digits to the right of the decimal** | In terms of assessing the accuracy of the final *settlement amount*, this column is derived from the *settlement* variable received by the *settlement* system with the MAXIMUM number of significant digits to the right of the decimal place. |
| Intermediate Rounding done by Settlements? | This column indicates whether or not any **INTERMEDIATE** rounding is done by the *IESO settlement* *process*. **This does NOT include the final rounding of *settlement amounts* to 2 decimal places as the last step in the calculation of ALL *charge types*.** |
| 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 |  |  |  |  |
| 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 |  |  |  |  |
| 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 |  |  |  |  |
| 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 |  |  |  |  |
| 206 | 10-Minute Spinning Non-Accessibility Settlement Amount | 1 | 3 | Yes | REAH =  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 =  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 =  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 |  |  |  |  |
| 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 |  |  |  |  |
| 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 |  |  |  |  |
| 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 |  |  |  |  |
| 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 |  |  |  |  |
| 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. |  |  |
| 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 |  |  |  |  |
| 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. |  |  |
| 1117 | Day-Ahead Market Net External Congestion Residual | 1 | 3 | No |  |  |  |  |
| 1118 | Real-Time External Congestion Residual Uplift | 1 | 3 | Yes | RT\_ECRL  RT\_ECRE  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 |  |  |  |  |
| 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 |  |  |  |  |
| 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 |  |  |  |  |
| 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 |  |  |  |  |
| 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 |  |  |  |  |
| 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 |  |  |  |  |
| 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 |  |  |  |  |
| 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. |  |  |
| 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. |  |  |
| 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. |  |  |
| 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. |  |  |
| 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. |  |  |
| 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. |  |  |
| 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. |  |  |
| 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. |  |  |
| 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. |  |  |
| 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. |  |  |
| 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. |  |  |
| 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. |  |  |
| 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. |  |  |
| 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. |  |  |
| 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 |  |  |  |  |
| 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 |  |  |  |  |
| 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 |  |  |  |  |
| 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, MIN(RT\_QSI\_DIGQ, AQEI)), RT\_DIPC)  OP(RT\_LMP, Max(RT\_LC\_EOP\_DIGQ,DAM\_DIGQ), RT\_DIPC)  Resulting Decimals: 2 | Profits are compared as applicable. |
| 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 |  |
| 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. |  |  |
| 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. |  |  |
| 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:  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. |  |  |
| 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. |  |  |
| 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:  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. |  |  |
| 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. |  |  |
| 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. |  |  |
| 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. |
| 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)  Resulting Decimals: 2 | Profits are compared as applicable. |  |  |
| 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)  OP(RT\_PROR, RT\_QSOR, RT\_OR\_DIPC)  Resulting Decimals: 2 | Profits are compared as applicable. |  |  |
| 1906 | Real-Time Make-Whole Payment – Lost Opportunity Cost for 10-Minute Non-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. |  |  |
| 1907 | Real-Time Make-Whole Payment – Lost Opportunity Cost for 30-Minute Operating 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)  Resulting Decimals: 2 | Profits are compared as applicable. |  |  |
| 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)  Resulting Decimals: 2 | Profits are compared as applicable |  |  |
| 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 |  |  |
| 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  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 | Profits are compared as applicable. |  |  |
| 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. |  |  |
| 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 |  |  |  |  |
| 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 |  |  |  |  |
| 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 |  |  |  |  |
| 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 |  |  |  |  |
| 9996 | Recovery of Costs | 2 | 2 | No |  |  |  |  |

### Settlement of Physical Bilateral Contracts

#### 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* |  |  | *Charge Type*  1104 |
| Dispatchable *delivery point*   * *generation resource* * *electricity storage resource* (injecting or withdrawing) * *dispatchable load* |  |  | *Charge type*  1100  1102 |
| *Intertie metering point* |  |  | *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* |  |  | *Charge type*  1115 |
| *Price responsive loads*  *Self-scheduling electricity storage resources* |  |  | *Charge type*  1105 |
| Dispatchable *delivery point*   * *generation resource* * *electricity storage resource* (injecting or withdrawing) * *dispatchable load* |  |  | *Charge type*  1101  1103 |
| *Intertie metering point* |  |  | *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**.

#### 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 | | | | | | | | | | | |

#### 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](https://www.ieso.ca/-/media/Files/IESO/Document-Library/Market-Rules-and-Manuals-Library/market-manuals/settlements/se-StatementAndDataFileFormatSpec.ashx) document located on the [Technical Interfaces](https://www.ieso.ca/en/Sector-Participants/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.* |
| 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* |

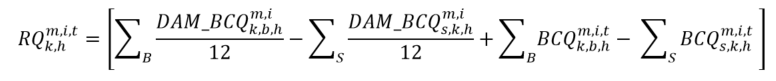
##### Reallocate Quantity

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**:



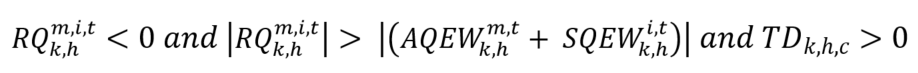
The RQ quantity is then used to either increase or decrease the *settlement amount* for the *hourly uplift* *charge type* ‘c’ in accordance with **MR Ch.9 s.3.10** as follows:



**Note:**

Condition for Reallocate Quantity calculation

Where:



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](#_Allocation_of_Hourly). Refer to [section 2.2](#_Charge_Types_and) for specific listings of *charge types* and their respective equations.

* End of Section -

## 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](#_Scope), 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.

### Variable Descriptions

The following Table 3-1 contains descriptions of variables used within [section 3.2](#_Toc140737042). Variables not defined in this table are as defined in [section 2.1](#_Variable_Descriptions).

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 |
| BRr | 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*. |
| CAEOmh,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* |
| CBMPk | Total net volume of electricity withdrawn from the *IESO-controlled grid* by applicable Class B market participant or licensed distributor that is also a *market participant* for the month | The total net volume of electricity withdrawn from the *IESO-controlled grid* by applicable Class B market participant (as that term is defined in the regulation) or licensed distributor that is a *market participant* ‘k’ for the month. | N/A | N/A – Refer to regulations. |
| CBRR | Global adjustment Class B recovery rate | Global Adjustment Class B recovery rate for the month per Ontario Regulation 429/04. | N/A | N/A – Refer to regulations. |
| CGC | * + - 1. 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\_BEk,hm,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\_BEk,hi,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\_BLk,hi,t | *Energy* Bidssubmitted into the *schedule of record* | Energy bidssubmitted 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 offeredprice in each *price-quantity pair* where offered prices ‘P’ are in column 1 and offered quantities ‘Q’ are in column 2. | 9.3.1.2B.7 and 9.3.8D.2 | Same as *IESO* *market rules* |
| DA\_CGC | Submitted Day-Ahead Combined Guaranteed Costs | EFFECTIVE OCTOBER 13, 2011, THIS VARIABLE IS NO LONGER USED IN THE CALCULATION OF ANY SETTLEMENT.  A financial amount consisting of fuel cost components defined on a *per-start* basis for a given *generation unit* calculated in a manner consistent with the applicable *market manual*, and encompassing the following elements:   1. Fuel and operation and maintenance (O&M) costs associated with unit synchronization to the *IESO-controlled 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\_DQSIk,hm,t | *Schedule of Record* Dispatch Quantity of Energy Scheduled for Injection at a delivery point | Day-aheadconstrained 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\_DQSIk,hi,t | *Schedule of Record* Dispatch Quantity of Energy Scheduled for Injection at an intertie metering point | Day-aheadconstrained 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\_DQSWk,hi,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\_ELMPhm,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\_ILMPhm,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\_SNLCk,hm | Speed-no-load costs submitted into the *schedule of record at a delivery point* | As-offered *speed-no-load cost* associated with *three-part offers* for a given *settlement hour* ‘h’ for *market participant* ‘k’ at *delivery point* ‘m’. | 9.3.1.2B.7 | Same as *IESO* *market rules.* |
| DA\_SNLCk,hp | 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\_SUCk,hm | 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\_SUCk,hp | 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.* |
| DIPCk,hm,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. |
| DIGQk,hm,t | Derived Interval Guaranteed Quantity | Portion of the day-aheadconstrained 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. |
| DQSIk,hm,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). |
| DQSRr,k,hm,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). |
| DQSWk,hm,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 |
| DRACPh | 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 |
| DRBOCk | 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 |
| DRCOk | 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 |
| DREBQmk,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 for the resource in the relevant *energy market billing,* theshall equal such | 9.3.1.10 | Same as *IESO market rules* |
| DRNPF | Demand Response Non-Performance Factor | The non-performance factor as listed in section 7.1 of Market Manual 12 that corresponds and applies to the month being settled. | N/A | Refer to Market Manual 5.5 |
| EIMk,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 | EIMk,h IS NOT A VARIABLE  EIMk,h is the output of a particular usage of the Operating Profit (OP) function defined within Chapter 9, section 3.8A.  EIMk,h Input variables into the Operating Profit (OP) Function include:  MQSI, EMP, and BE. |
| EMPhi,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*. |
| EMPhm,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*. |
| EMPhREF,t | 5-minute Energy Market Reference Price | Reference energy *market price* used to value losses in the calculation of the *Transmission Charge Reduction Fund*[[3]](#footnote-4) during in *metering interval* ‘t’ of *settlement hour* ‘h’. | 9.3.1.3  and  9.3.6.2 | Same as *IESO* *market rules*. |
| FPhm | Fixed Energy Rate | A fixed *energy* rate for all *metering intervals* in *settlement hour* ‘h’. | N/A – subject to regulations made pursuant to *Ontario Energy Board Act, 1998* until March 31, 2005 and by the *OEB* under such regulations commencing April 1, 2005. | N/A – Refer to regulations. |
| FPChm | 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 |
| HOEPh | Hourly Ontario Energy Price | *Hourly Ontario Energy Price* in *settlement hour* ‘h’. | 9.3.1.3 | Same as *IESO* *market rules*. |
| IOG\_FVk,hi | 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\_FVk,hi 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 allocated to Class B customers that was deferred in April, May and June of 2020. | N/A | N/A – Refer to regulations. |
| MChm | 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 MQSIk,hi,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’ (MQSIk,hi,t) paired with the corresponding component of the intertie offerguarantee 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*. |
| MLPk,hm,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\_CONSk,hm,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. |
| MQSIk,hm,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,hm,t | Adjusted Market Quantity Scheduled for Injection | EFFECTIVE OCTOBER 13, 2011, THIS VARIABLE IS NO LONGER USED IN THE CALCULATION OF ANY SETTLEMENT. Used for the calculation of the IOG OFFSET settlement amount. MQSI{adj}k,h i,t is each (and where applicable, adjusted) quantity of energy scheduled for injection in the market schedule by market participant ‘k’ at an intertie metering point ‘i’ in metering interval ‘t’ of settlement hour ‘h’ corresponding with each quantity, MQSIx\*,k,h i,t in matrix MI, row x\*. | 9.3.8A.4 | Same as *IESO* *market rules*. |
| MQSWk,hm,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  BE, BL, BRr  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 (EIMk,h) sub-component of the Intertie Offer Settlement Credit (IOG) using the following input variables:  MQSI  BE  EMP |
| OPCAPk,hm,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,hi | 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,hi is an adjusted component of The congestion management *settlement* credit *settlement amount* (CMSC) for *market participant* ‘k’ at *intertie metering point* ‘i’ for *settlement hour* ‘h’ in which the constrained schedule is the lesser of PDR\_DQSIk,hi,t or DQSIk,hi,t but in all instances, greater than or equal to MQSIk,hi,t . | 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. |
| 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\_BEk,hi,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\_BLk,hi,t | *Energy* Bidsubmitted into the Pre-dispatch | Energy bidssubmitted 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\_DQSIk,hi,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\_DQSWk,hi,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\_ELMPhm,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\_EMPhm,t | Pre-dispatchenergy 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\_ILMPhm,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\_BEk,hi,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\_DQSIk,hi,t | *Pre-dispatch of record* dispatch quantity scheduled for injection at an *intertie metering point* | EFFECTIVE OCTOBER 13, 2011, THIS VARIABLE IS NO LONGER USED IN THE CALCULATION OF ANY SETTLEMENT.  *Pre-dispatch of record* constrained quantity scheduled for injection by *market participant* ‘k’ for an import transaction at *intertie metering point* ‘i’ during *metering interval* ‘t’ of *settlement hour* ‘h’. | 9.3.1.2A | Same as *IESO* *market rules* |
| PDR\_DQSIk,hm,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* |
| RPPVAk | 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. |
| SQRORr,k,hm,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*. |
| Xhm,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* |

### 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.

#### 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 | NEMSCk,h | 9.3.3.2 | **\*\*CALCULATIONS FOR *CHARGE TYPE* 100 END APRIL 30, 2023\*\***  For *dispatchable* *facilities* or an *intertie metering point* associated with:   1. An injecting *boundary* *entity*; 2. A withdrawing *boundary* *entity* where the associated *intertie* *congestion* *price* is less than zero; 3. A withdrawing *boundary* *entity* conducting a wheeling through transaction that is linked as per Chapter 7, section 3.5.82 of the *market* *rules*   Equation for charge type Net Energy Market Settlement for Generators and Dispatchable Load | Interval | Either Way | 13 | 13 | 0 | 13 |  |
| 101 | Net Energy Market Settlement for Non-dispatchable Load | NEMSCk,h | 9.3 | **\*\*CALCULATIONS FOR *CHARGE TYPE* 101 END APRIL 30, 2023\*\***  Equation for charge type Net Energy Market Settlement for Non-dispatchable Load | Hourly | Either Way | 13 | N/A | N/A | N/A |  |
| 103  MRP retired | Transmission Charge Reduction Fund | TCRFh | 9.3.6.2  And  8.4.18 | Equation for charge type Transmission Charge Reduction Fund | 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 | TRSCk,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*.\*\***  Equation for charge type Transmission Rights Settlement Credit | Hourly | Due MP | 0 | 0 | 0 | 0 |  |
| 105  MRP retired | Congestion Management Settlement Credit for Energy | CMSCk,h | 9.3.5.2  to  9.3.5.7 | Congestion Management Settlement Credit for Energy  Subject to the mathematical sign of (DQSI-MQSI) being equal to the mathematical sign of (AQEI-MQSI). AQEIk,hm,t and EMPhm,t may be substituted with SQEIk,h i,t and EMPhi,t respectively, where the application of this equation pertains to *intertie metering point* ‘i’.  or  Congestion Management Settlement Credit for Energy  Subject to the mathematical sign of (DQSW-MQSW) being equal to the mathematical sign of (AQEW-MQSW). AQEWk,hm,t and EMPhm,t may be substituted with SQEWk,h i,t and EMPhi,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:  Congestion Management Settlement Credit for Energy  Refer to 9.3.5.2 for the definition of the Operating Profit (OP) function referenced above. | Interval | Either Way | 13 | 13 | 13 | 13 | This *charge* *type* holds the *market participant* to the expected profits implied by the *market schedule* derived on *dispatch data* provided by that *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 Spinning Reserve | CMSCr,k,h | 9.3.5.2 | Congestion Management Settlement Credit for 10 Minute Spinning Reserve  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*. |
| 107  MRP retired | Congestion Management Settlement Credit for 10 Minute Non-spinning Reserve | CMSCr,k,h | 9.3.5.2 | Congestion Management Settlement Credit for 10 Minute Non-spinning Reserve  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 | CMSCr,k,h | 9.3.5.2 | Congestion Management Settlement Credit for 30 Minute Operating Reserve  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*. |
| 111 | Northern Pulp and Paper Mill Electricity Transition Program Settlement Amount | N/A | N/A | Northern Pulp and Paper Mill Electricity Transition Program Settlement Amount  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 \*\***  Ontario Power Generation Rebate  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 |
| 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 \*\***  Northern Industrial Electricity Rate Program Settlement Amount  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 | RDSAk,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*:  Ramp Down Settlement Amount  Where:  s\* is the highest indexed row of BE such that Qs\*  Q  Qn and where, Q0=0  Using the terms below, let RDCk,hm,t be expressed as follows:  Ramp Down Settlement Amount  Ramp Down Settlement Amount | 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. |
| 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 | IOGk,h  and  IOGk,hOFFSET | 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 (EIMk,h) as follows:  Intertie Offer Guarantee Settlement Credit – Energy  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:  Intertie Offer Guarantee Settlement Credit – Energy  (Refer to 9.3.8A.4 for the derivation of the variable QSI{adj}k,hi,t , OPE’k,hi and the proper context of the matrix notation MIk,ht[n,1] used above ). | 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 section 3.5.8.1 of Chapter 7. |
| 133  MRP retired | Generation Cost Guarantee Payment | N/A | 9.4.7B | Dispatchable *delivery points:*  Generation Cost Guarantee Payment  **Subject to:**  Generation Cost Guarantee Payment  Where ‘CGC’ is a *Submitted* Co*mbined 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,hm,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).  Generation Cost Guarantee Payment   1. Where the COST function is defined as follows:   Equation for COST Function  where:   * B is the n x 2 matrix (B) of offered *price-quantity* *pairs* (Pi , Qi) * s\* is the highest indexed row of B such that Qs\*-1 ≤ Q ≤ Qs\* and where Q0=0  1. 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. 2. Where ‘T\*’ is the set of *metering intervals ‘*t’ in the set of all *settlement hours* ‘H1’   Where CMSC\_REV k,hm,t is any real-time CMSC(TD k,h,105m,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,105m,t) for the same interval is greater than zero. 2. If MQSI k,hm,t and max(DQSI k,hm,t,AQEI k,hm,t) >= MLP, then CMSC\_REVk,hm,t = 0. 3. In the case of a *constrained-off event*:    1. If MQSI k,hm,t < MLP, then CMSC\_REV k,hm,t = TD k,h,105m,t    2. If MQSI k,hm,t >= MLP and max(DQSI k,hm,t,AQEI k,hm,t) <= MLP, then CMSC\_REV k,hm,t = OP(EMP hm,t,MLP,BE) – OP(EMP,max(DQSI k,hm,t,AQEI k,hm,t),BE). 4. In the case of a *constrained-on event*: 5. If MQSI k,hm,t < MLP and min(DQSI k,hm,t,AQEI k,hm,t) < MLP, then   CMSC\_REV k,hm,t = TD k,h,105m,t   1. If MQSI k,hm,t <= MLP and min(DQSI k,hm,t, AQEI k,hm,t) >=MLP, then   CMSC\_REV k,hm,t = OP(EMP hm,t,MQSI k,hm,t,BE) – OP(EMP hm,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\_IFCk,h | 9.3.8C.3 | Real-time Import Failure Charge  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\_ISDk,hi,t = MAX (PD\_DQSIk,hi,t – DQSIk,hi,t, 0) | Hourly | Due *IESO* | N/A | 13 | N/A | N/A | Subject to exemptions under the provisions of 9.3.8C.2.2. |
| 136  MRP retired | Real-time Export Failure Charge | RT\_EFCk,h | 9.3.8C.5 | Real-time Export Failure Charge  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\_ESDk,hi,t = MAX (PD\_DQSWk,hi,t – DQSWk,hi,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:**  Fixed Energy Rate Settlement Amount (dispatchable locations) Where net uncovered consumption > 0:  **Where net uncovered consumption = 0:**  **Fixed Energy Rate Settlement Amount (dispatchable locations) Where net uncovered consumption < 0:**  **SUBJECT TO:** Net uncovered consumption = MAX [T,m (AQEWk,hm,t - s BCQs,k,hm,t),0]  **Fixed Energy Rate Settlement Amount (non-dispatchable locations):**  **Where net uncovered consumption > 0:**  Fixed Energy Rate Settlement Amount (non-dispatchable locations): Where net uncovered consumption > 0  **Where net uncovered consumption = 0:**  Fixed Energy Rate Settlement Amount (non-dispatchable locations): Where net uncovered consumption <  0  **SUBJECT TO:**  Net uncovered consumption = MAX [T,m (AQEWk,hm,t - s BCQs,k,hm,t),0]  **SUBJECT TO:**  Net uncovered consumption = MAX [T,m (AQEWk,hm,t - s BCQs,k,hm,t),0] | Hourly (type ‘DP’ records only.  Refer to [Format Specifications for Settlement Statement Files and Data Files](https://www.ieso.ca/-/media/Files/IESO/Document-Library/Market-Rules-and-Manuals-Library/market-manuals/settlements/se-StatementAndDataFileFormatSpec.ashx) for further details) | Either Way | N/A | N/A | N/A | N/A | Eligibility, rates, and other implementation details subject to government regulation. |
| 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.  Fixed Wholesale Charge Rate Settlement Amount  Where:  ‘H’ is all *settlement hours* ‘h’ during the *billing period;* and*,*  ‘C’ is a designated group of *charge types* ‘c’ prescribed by government regulation (and associated rulings by the *Ontario Energy Board*) and consisting of the cumulative sum of the following *charge types*:  **150, 155, 168, 170, 182, 183, 184, 250, 252, 254, 450, 452, 454, 550, 753, 9990** | Monthly | Either Way | N/A | N/A | N/A | N/A | Eligibility, rates, and other implementation details subject to government regulation. |
| 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.:  **Global Adjustment Settlement Amount for Fort Frances Power Corporation Distribution Inc**  For other market participants:  Global Adjustment Settlement Amount for other market participants  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, 197, 198, 1380, 1381, 1382, 1383, 1384, 1385, 1386, 1390, 1391, 1392, 1393, 1394, 1395, 1396, 1397, 1398, 1450, 1460, 1462 and 1464.** | Monthly | Due MPs | 13 | N/A | N/A | N/A | Eligibility, rates, and other implementation details subject to government regulation. |
| 150  MRP retired | Net Energy Market Settlement Uplift | N/A | 9.3.9.1 | Net Energy Market Settlement Uplift  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 RQk,hm,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:  Net Energy Market Settlement Uplift | 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 | Congestion Management Settlement Uplift  Where ‘T’ is the set of 12 *metering intervals* ‘t’ during *settlement hour* ‘h’.  Where RQk,hm,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:  Congestion Management Settlement Uplift | 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 Transition Program Balancing Amount | N/A | N/A | Northern Pulp and Paper Mill Electricity Transition Program Balancing Amount  Where ‘k’ is part of a subset of eligible *market participants* ‘k’. | Quarterly | Due *IESO* | 0 | N/A | N/A | N/A | This program ends on September 30, 2010. |
| 162 | Ontario Power Generation Rebate Debit | N/A | N/A | **\*\* CALCULATIONS FOR *CHARGE TYPE* 162 END April 30, 2009 \*\***  Payment (n) = H [(HOEPh – ORL) x (ONPAOh 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. |
| 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 | Additional Compensation for Administrative Pricing 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’. | 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 | Local Market Power Rebate  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 \*\***    Northern Industrial Electricity Rate Program Balancing Amount  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 | Generation Cost Guarantee Recovery Debit  Where:  ‘C’ is the set of the following *charge types* ‘c’ as follows*:*  **133, 137**  ‘H’ is the set of all *settlement hours* ‘h’ in the month.  ‘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 |  |
| 184 | Demand Response Debit | N/A | 9.4.7C  9.4.7F | Demand Response Debit  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 \*\***  Fixed Energy Rate Balancing Amount  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](https://www.ieso.ca/-/media/Files/IESO/Document-Library/Market-Rules-and-Manuals-Library/market-manuals/settlements/se-StatementAndDataFileFormatSpec.ashx) 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 \*\***  Fixed Wholesale Charge Rate Balancing Amount  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. \*\***  Renewable Generation Balancing Amount  Where ‘K’ is the set of all *market participants*‘k’.  Where TDk,148 is the *settlement amount* of *charge type*148 for the month for *market participant* ‘k’. | Pending | Due *IESO* | 0 | N/A | N/A | N/A | Implementation details subject to government regulation. |
| 200  MRP retired | 10 Minute Spinning Reserve Market Settlement Credit | ORSCk,h | 9.3.4.1 | 10 Minute Spinning Reserve Market Settlement Credit | Interval | Due MP | 13 | 13 | N/A | N/A |  |
| 202  MRP retired | 10 Minute Non-spinning Reserve Market Settlement Credit | ORSCk,h | 9.3.4.1 | 10 Minute Non-spinning Reserve Market Settlement Credit | Interval | Due MP | 13 | 13 | N/A | N/A |  |
| 204  MRP retired | 30 Minute Operating Reserve Market Settlement Credit | ORSCk,h | 9.3.4.1 | 30 Minute Operating Reserve Market Settlement Credit | Interval | Due MP | 13 | 13 | N/A | N/A |  |
| 206  MRP updated | 10-Minute spinning non-Accessibility Settlement Amount | ORSCBr,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,(TAORk,hm,t – AQORr1,k,hm,t) × PRORr1,hm,t)  Where:  TAORk,hm,t =  MAX(0,AQEWk,hm,t – MChm,t) for *dispatchable loads*  *or,*  MAX(0,MAX\_CAPk,hm,t – AQEIk,hm,t) for *generators*  **For aggregated generators:**  ORIA\_CAr1,k,hM,t × ORCFr1,k,hm,t × PRORr1,hm,t  Where:  ORIA\_CAr1,k,hM,t = MIN(0,TAOR\_CAk,hM,t − ∑M AQORr1,k,hm,t)  TAOR\_CAk,hM,t =  MAX(0,∑M (MAX\_CAPk,hm,t – AQEIk,hm,t))  ORCFr1,k,hm,t = ORIAr1,k,hm,t / (∑M1 ORIAr1,k,hm,t), and M1 represents the set of all delivery points ‘m’ offering 10-minute synchronized OR  ORIAr1,k,hm,t = MIN(0,(TAORk,hm,t – AQORr1,k,hm,t)) | Interval | Due *IESO* | 13 | N/A | N/A | N/A | Please refer to MR-00467 |
| 208  MRP updated | 10-Minute non-Spinning non-Accessibility Settlement Amount | ORSCBr,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,TAORk,hm,t – AQORr1,k,hm,t) - AQORr2,k,hm,t) × PRORr2,hm,t)  Where:  TAORk,hm,t =  MAX(0,AQEWk,hm,t – MChm,t) for *dispatchable loads*  *or,*  MAX(0,MAX\_CAPk,hm,t – AQEIk,hm,t) for *generators*  **For aggregated generators:**  ORIA\_CAr2,k,hM,t × ORCFr2,k,hm,t × PRORr2,hm,t  Where:  ORIA\_CAr2,k,hM,t = MIN(0,TAOR\_CAk,hM,t - ∑M AQORr2,k,hm,t)  TAOR\_CAk,hM,t =  MAX(0,∑M (MAX\_CAPk,hm,t – AQEIk,hm,t))  ORCFr2,k,hm,t = ORIAr2,k,hm,t / (∑M2 ORIAr2,k,hm,t), and M2 represents the set of all delivery points ‘m’ offering 10-minute non-synchronized OR  ORIAr2,k,hm,t = MIN(0,(TAORk,hm,t – AQORr2,k,hm,t)) | Interval | Due *IESO* | 13 | N/A | N/A | N/A | Please refer to MR-00467 |
| 210  MRP updated | 30-Minute non-Accessibility Settlement Amount | ORSCBr,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,TAORk,hm,t – AQORr1,k,hm,t – AQORr2,k,hm,t) - AQORr3,k,hm,t) × PRORr3,hm,t)  Where:  TAORk,hm,t =  MAX(0,AQEWk,hm,t – MChm,t) for *dispatchable loads*  *or,*  MAX(0,MAX\_CAPk,hm,t – AQEIk,hm,t) for *generators*  **For aggregated generators:**  ORIA\_CAr3,k,hM,t × ORCFr3,k,hm,t × PRORr3,hm,t  Where:  ORIA\_CAr3,k,hM,t = MIN(0,TAOR\_CAk,hM,t - ∑M AQORr3,k,hm,t)  TAOR\_CAk,hM,t =  MAX(0,∑M (MAX\_CAPk,hm,t – AQEIk,hm,t))  ORCFr3,k,hm,t = ORIAr3,k,hm,t / (∑M3 ORIAr3,k,hm,t), and M3 represents the set of all delivery points ‘m’ offering 30-minute OR  ORIAr3,k,hm,t = MIN(0,(TAORk,hm,t – AQORr3,k,hm,t)) | Interval | Due *IESO* | 13 | N/A | N/A | N/A | Please refer to MR-00467 |
| 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 \*\***  Debt Retirement Credit | 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 \*\***  OPA Administration Credit  Where ‘K’ is the set of all *market* *participants* ‘k’.  Where TDk,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. |
| 752 | Debt Retirement Charge | N/A | 9.4.6 | **\*\* CALCULATIONS FOR *CHARGE TYPE* 702 END MARCH 31, 2018 \*\***  Debt Retirement Charge  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 \*\***  OPA Administration Charge  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 than or equal to MMCP, indicating that it is a non-dispatchable in that range.  Self-Induced Dispatchable Load CMSC Clawback  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 *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:   1. The constrained schedule is labeled with the reason code ‘ORA’. 2. The interval is 1-3 intervals before an interval with the ‘ORA’ code. 3. 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:   1. It is one of the first 3 intervals of the second hour when ramping up. 2. 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. | 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. |
| 1051  MRP retired | Ramp-Down CMSC Claw Back | RDCBk,h | 9.3.5.1G | Ramp-Down CMSC Claw Back  (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 | NEMSCk,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*.\*\***  Real-Time Energy Settlement Amount for Dispatchable Generators | Interval | Either Way | 13 | N/A | N/A | N/A |  |
| 1103  MRP updated | Real-Time Energy Settlement Amount for Dispatchable Loads | NEMSCk,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*.\*\***    Real-Time Energy Settlement Amount for Dispatchable Loads | Interval | Either Way | 13 | N/A | N/A | N/A |  |
| 1111  MRP updated | Real-Time Energy Settlement Amount for Imports | NEMSCk,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*.\*\***    Real-Time Energy Settlement Amount for Imports | Interval | Either Way | N/A | 13 | N/A | N/A |  |
| 1113  MRP updated | Real-Time Energy Settlement Amount for Exports | NEMSCk,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*.\*\***    Real-Time Energy Settlement Amount for Exports | Interval | Either Way | N/A | N/A | 0 | 13 |  |
| 1114  MRP retired | Real-Time Energy Settlement Amount for Non-Dispatchable Generators | NEMSCk,h | 9.3 | Real-Time Energy Settlement Amount for Non-Dispatchable Generators | Hourly | Either Way | 13 | N/A | N/A | N/A |  |
| 1115  MRP updated + name change | Real-Time Energy Settlement Amount for Non-Dispatchable Loads | NEMSCk,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*.\*\***  Real-Time Energy Settlement Amount for Non-Dispatchable Loads | Hourly | Either Way | 13 | N/A | N/A | N/A |  |
| 1130 | Day-Ahead Intertie Offer Guarantee Settlement Credit | DA\_IOGk,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:*  Day-Ahead Intertie Offer Guarantee Settlement Credit  Or, in the case of an import transaction subject to a *constrained on event* in the *real-time market:*  Day-Ahead Intertie Offer Guarantee Settlement Credit  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’.  TDk,h,105i 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’. | Hourly | Due MP | N/A | 13 | 13 | 13 |  |
| 1131  MRP retired | Intertie Offer Guarantee Settlement Credit | IOGk,h | 9.3.8A | The Day-Ahead Intertie Offer Guarantee *settlement amount* is derived as follows:  Intertie Offer Guarantee Settlement Credit  Where  **DA\_IOG\_COMP1:**  DA_IOG_COMP1  **DA\_IOG\_COMP2:**    DA_IOG_COMP2  **DA\_IOG\_COMP3:**  Component 3 is calculated when:  the CMSC for energy (TDk,h,105m,t) for the same metering interval is a value other than zero.  For Component 3 (DA\_IOG\_COMP3), the six scenarios of the possible orderings of the generator’s DA\_DQSI, DQSI and MQSI are as follows:   1. DQSI >= MQSI >= DA\_DQSI 2. MQSI >= DQSI >= DA\_DQSI 3. DQSI > DA\_DQSI > MQSI 4. MQSI > DA\_DQSI > DQSI 5. DA\_DQSI >= DQSI > MQSI 6. DA\_DQSI >= MQSI > DQSI   Scenario 1 and 2:  0  Scenario 3:  DA_IOG_COMP3 for scenario 3  Scenario 4:  DA_IOG_COMP3 for scenario 4  Scenario 5 and 6:  TDk,h,105m,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.  DA_IOG_COMP3 for scenario 5 and 6  Where EMPhi,t  = 0  The Intertie Offer Guarantee *settlement amount* is derived from an hourly *Energy* Import sub component (EIMk,h) as follows:  RT-IOGk,h = EIMk,h  The Real-Time Intertie Offer Guarantee (RT-IOGk,h) *settlement amount* is derived as follows:  Real-Time Intertie Offer Guarantee  Where  ‘I’ is the set of relevant *intertie metering points* ‘i’.  ‘T’ is the set of all *metering intervals* ‘t’ during *settlement hour* ‘h’.  ‘OP’ is the operating profit function defined in *IESO* *market rules* section 9.3.8A.2.  The IOG\_OFFSET component of this *charge type* is calculated as follows:  **The Day-Ahead IOG rate:**  DA\_IOG\_RATE = IF [DA\_IOG is not NULL, DA\_IOG / min(DA\_DQSI, DQSI), 0]  **The Real-Time IOG rate:**  RT\_IOG\_RATE = IF[RT\_IOG is NULL, 0, RT\_IOG/DQSI]  **The matrix is arranged in ascending order on DA\_IOG\_RATE and the day-ahead import quantities are offset against the day-ahead export schedule quantities:**  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  **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) | Hourly | Due MP | N/A | 13 | N/A | N/A |  |
| 1133 | Day-Ahead Generation Cost Guarantee Payment | DA\_GCGk,h | 9.4.7D | **\*\*CALCULATIONS FOR *CHARGE TYPE* 1133 END OCTOBER 12, 2011. \*\***  Dispatchable *delivery points:*  Day-Ahead Generation Cost Guarantee Payment  **Subject to:**  Day-Ahead Generation Cost Guarantee Payment  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”).  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,hm,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).  Day-Ahead Generation Cost Guarantee Payment   1. Where the COST function is defined as follows:   Equation for COST Function  where:   * B is the n x 2 matrix (B) of offered *price-quantity* *pairs* (Pi , Qi) * s\* is the highest indexed row of B such that Qs\*-1 ≤ Q ≤ Qs\* and where Q0=0  1. 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*      1. Where ‘T\*’ is the set of metering intervals ‘t’in the set of all settlement hours ‘H2’   Where CMSC\_REV k,hm,t is any real-time CMSC(TD k,h,105m,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,105m,t) for the same interval is greater than zero. 2. If MQSI k,hm,t and max(DQSI k,hm,t,AQEI k,hm,t) >= MLP, then CMSC\_REVk,hm,t = 0. 3. In the case of a *constrained-off event*:    1. If MQSI k,hm,t < MLP, then CMSC\_REV k,hm,t = TD k,h,105m,t    2. If MQSI k,hm,t >= MLP and max(DQSI k,hm,t,AQEI k,hm,t) <= MLP, then   CMSC\_REV k,hm,t = OP(EMP hm,t,MLP,BE) – OP(EMP,max(DQSI k,hm,t,AQEI k,hm,t),BE).   1. In the case of a *constrained-on* *event*: 2. If MQSI k,hm,t < MLP and min(DQSI k,hm,t,AQEI k,hm,t) < MLP, then CMSC\_REV k,hm,t = TD k,h,105m,t 3. If MQSI k,hm,t <= MLP and min(DQSI k,hm,t, AQEI k,hm,t) >=MLP, then   CMSC\_REV k,hm,t = OP(EMP hm,t,MQSI k,hm,t,BE) – OP(EMP hm,t,MLP,BE)  (Refer to applicable *market manual*) | Hourly | Due MP | 13 | N/A | N/A | N/A |  |
| 1134  MRP retired | Day-Ahead Linked Wheel Failure Charge | DA\_LWFCk,h | 9.3.8E | MAX[(-1) \* [(DA\_LWSDk,hi) \* MAX[0,( DA\_PSk,hi – PD\_PSk,hi)]], (RT\_IFC\_DALWk,hi + RT\_EFC\_DALWk,hi)]  Where:  DA\_LWSDk,hi,t = MAX[MAX (DA\_DQSIk,hi,t – PD\_DQSIk,hi,t, DA\_DQSWk,hi,t – PD\_DQSWk,hi,t),0]  RT\_IFC\_DALWk,hi = I,T (-1) \* MIN[MAX[ 0, (EMPhm,t + PB\_IMht – PD\_EMPhm,t) \* MAX (DA\_DQSIk,hi,t – PD\_DQSIk,hi,t, 0)], (MAX(0, EMPhm,t)\* MAX (DA\_DQSIk,hi,t – PD\_DQSIk,hi,t, 0))]  RT\_EFC\_DALWk,hi = I,T (-1) \* MIN[MAX[ 0, (PD\_EMPhm,t – EMPhm,t – PB\_EXht) \* MAX (DA\_DQSWk,hi,t – PD\_DQSWk,hi,t, 0)], (MAX(0, PD\_EMPhm,t) \* MAX (DA\_DQSWk,hi,t – PD\_DQSWk,hi,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 |  |
| 1135  MRP retired | Day-Ahead Import Failure Charge | DA\_IFCk,h | 9.3.8B | Day-Ahead Linked Wheel Failure Charge  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’.  Day-Ahead Linked Wheel Failure Charge | Hourly | Due *IESO* | N/A | 13 | N/A | N/A | Subject to exemptions under the provisions of 9.3.8B.1.2 |
| 1136  MRP retired | Day-Ahead Export Failure Charge | DA\_EFCk,h | 9.3.8D | Day-Ahead Export Failure Charge  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’.  Day-Ahead Export Failure Charge | Hourly | Due *IESO* | N/A | N/A | 0 | 13 |  |
| 1137 | Intertie Offer Guarantee Reversal | **Context 1:**  IOG\_REVk,h  **Context 2:**  DA\_IOG {adj}k,hi | 9.3.8A.1.2  and  9.3.8A.7 to 9.3.8A.9 | **\*\*CALCULATIONS FOR *CHARGE TYPE* 1137 END OCTOBER 12, 2011.\*\***  **NOTE**: This *charge type* is used in two separate contexts as follows:  **Context 1:**  When a day-ahead Intertie Offer Guarantee and a real-time Intertie Offer Guarantee apply to the same import transaction, the lower of the two is reversed by this *charge type*.  -1 x TDk,h,ci  Where:  ‘c’ is *charge type* 130 or 1130 as the case may be such that:  TDk,h,c i= MIN (TDk,h,130i ,TDk,h,1130i)  **Context 2:**  In cases where this *charge type* is used for the purposes of applying the intertie offer guarantee adjustment (DA\_IOG{adj}k,hi), the *settlement amount* applied is DA\_IOG{adj}k,hi  and is calculated as follows:  Intertie Offer Guarantee Reversal  Where:  TDk,h,100i, TDk,h,1130i  , TDk,h,130i  and TDk,h,105i  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’. | **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. |
| 1139 | Intertie Failure Charge Reversal | IFC\_REVk,h | 9.3.8C.6 | **\*\*CALCULATIONS FOR *CHARGE TYPE* 1139 END OCTOBER 12, 2011.\*\***  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 x TDk,h,ci  Where:  ‘c’ is *charge type* 135 or 1135 as the case may be such that:  TDk,h,c i= MIN (-1 x TDk,h,135i ,-1 \* TDk,h,1135i) | Hourly | Due *IESO* | N/A | 13 | N/A | N/A |  |
| 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:*    Ontario Fair Hydro Plan Eligible RPP Consumer Discount Settlement Amount | 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 Settlement 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 (OFHP) for Eligible Non-RPP Customers” | Monthly | Due LDCs, Unit Sub-Meter Providers and eligible MPs either way | 13 | N/A | N/A | N/A |  |
| 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 \*\***  Ontario Fair Hydro Plan Eligible RPP Consumer Discount Balancing Amount  Where ‘K’ is the set of all *market participants* ‘k’.    Where TDk,1142 is the total *settlement amount* of *charge type* 1142 for the month for *market participant* ‘k’. | Monthly | Due *IESO* | N/A | N/A | N/A | N/A | Eligibility, rates, and other implementation details subject to government and OEB regulations. |
| 1193 | Ontario Fair Hydro Plan Eligible Non-RPP Consumer Discount Balancing Amount | N/A | N/A | **\*\*REPEALED EFFECTIVE NOVEMBER 1, 2019\*\***  Ontario Fair Hydro Plan Eligible Non-RPP Consumer Discount Balancing Amount  Where ‘K’ is the set of all *market participants* ‘k’.  Where TDk,1143 is the total *settlement amount* of *charge type* 1143 for the month for *market participant* ‘k’. | Monthly | Due *IESO* | N/A | N/A | N/A | N/A | Eligibility, rates, and other implementation details subject to government and OEB regulations. |
| 1194 | Ontario Fair Hydro Plan Financing Entity Balancing Amount | N/A | N/A | **\*\*REPEALED EFFECTIVE NOVEMBER 1, 2019\*\***  Ontario Fair Hydro Plan Financing Entity Balancing Amount  Where ‘K’ is the set of all *market participants* ‘k’.  Where TDk,1144 is the total *settlement amount* of *charge type* 1144 for the month for *market participant* ‘k’. | Monthly | Due *IESO* | N/A | N/A | N/A | N/A | Implementation details subject to government regulations |
| 1195 | Ontario Fair Hydro Plan Financing Entity Balancing Interest | N/A | N/A | **\*\*REPEALED EFFECTIVE NOVEMBER 1, 2019\*\***  Ontario Fair Hydro Plan Financing Entity Balancing Interest  Where ‘K’ is the set of all *market participants* ‘k’.  Where TDk,1145 is the total *settlement amount* of *charge type* 1145 for the month for *market participant* ‘k’. | Monthly | Due *IESO* | N/A | N/A | N/A | N/A | Implementation details subject to government regulations |
| 1300 | Capacity Based Demand Response Program Availability Payment Settlement Amount | N/A | N/A | **\*\*CALCULATIONS FOR *CHARGE TYPE* 1300 ENDED ON OCTOBER, 2018.\*\***  Capacity Based Demand Response Program Availability Payment Settlement Amount  Where:  ‘AAR’ means ‘Adjusted Availability Rate’.  ‘H’ is the total hours a DRMP is available in a program month.  ‘HA’ means ‘Hours of Availability’.  ‘MCMW’ means ‘Monthly Contracted MW’. | 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.\*\***  Capacity Based Demand Response Program Availability Over-Delivery Settlement Amt  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)**  Capacity Based Demand Response Program Availability Set-Off Settlement Amount: : Availability Set-Off (Reliability)  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)**  Capacity Based Demand Response Program Availability Set-Off Settlement Amount: Availability Set-Off (Timely Confirmation)  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)**  Capacity Based Demand Response Program Availability Set-Off Settlement Amount: Availability Set-Off (Low Confirmation)  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. | Monthly | Due *IESO* | 13 | N/A | N/A | N/A |  |
| 1303 | Capacity Based Demand Response Program Utilization Payment Settlement Amount | N/A | N/A | **\*\*CALCULATIONS FOR *CHARGE TYPE* 1303 ENDED ON OCTOBER, 2018.\*\***  Capacity Based Demand Response Program Utilization Payment Settlement Amount  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 |  |
| 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)**  Capacity Based Demand Response Program Utilization Set-Off Settlement Amount: Reliability  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)**  Capacity Based Demand Response Program Utilization Set-Off Settlement Amount: Timely Confirmation  This formula applies when the DRMP, regardless of Activation, has failed to deliver, or delivers late, a Confirmation that is required by the IESO.  Where:  ‘CDP’ (Contracted Dispatch Period) means four consecutive hours. Each Contracted Dispatch Period shall occur within the hours of Availability, and shall occur within and no more than once in accordance with the Daily Schedule.  ‘MCMW’ has the same meaning as defined above.  ‘PSO’ has the same meaning as defined above.  ‘UR’ has the same meaning as defined above.  **C: Utilization Set-Off (Low Confirmation)**  Capacity Based Demand Response Program Utilization Set-Off Settlement Amount: Low Confirmation  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. | Monthly | Due *IESO* | 13 | N/A | N/A | N/A |  |
| 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:   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:  Capacity Based Demand Response Program Planned Non-Performance Event Set-Off Amt : The Non-Activation Day Non-Performance Availability Set-Off amount  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:  Capacity Based Demand Response Program Planned Non-Performance Event Set-Off Amt : The Activation Day Non-Performance Availability Set-Off amount  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%. | Monthly | Due *IESO* | 13 | N/A | N/A | N/A |  |
| 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.\*\***  Capacity Based Demand Response Program Measurement Data Set-Off Settlement Amt  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 x BDR x HAE)  Where:  ‘MCMWR’ (Monthly Contracted MW Reduction), means the MW of demand reduction in the Monthly Contracted MWs.  ‘BDR’ (Buy-Down Rate), means the Buy-Down Rate, expressed in $/MW.  ‘HAE’ (Hours of Availability Elapsed), means the number of Hours of Availability that have elapsed in the Schedule Term up to the date that the reduction takes effect.  For the Buy-Down of the Daily Schedules the payment is:  = (MCMW 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. | Monthly | Due *IESO* | 13 | N/A | N/A | N/A |  |
| 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 |
| 1311 | Demand Response Pilot – Availability Charge | N/A | N/A | **\*\*CALCULATIONS FOR *CHARGE TYPE* 1311 ENDED ON APRIL, 2018.\*\***  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 | **\*\*CALCULATIONS FOR *CHARGE TYPE* 1312 ENDED ON APRIL, 2018.\*\***  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 | **\*\*CALCULATIONS FOR *CHARGE TYPE* 1313 ENDED ON APRIL, 2018.\*\***  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 | CAACmk | 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***:**  ∑H(-1) x Max( 0, (CCOmk,h - DREBQmk,h)) x CACPzh x CNPFtm  Where:   1. ‘H’ is the set of all *settlement hours* within the *availability window* during the relevant *trading day*; 2. If the *capacity market participant* did not submit a *demand response energy bid* for its *hourly demand response resource* or *capacity dispatchable load resource*, as the case may be, for *settlement hour* ‘h’ in the day-ahead commitment process or failed to maintain such *energy bid* through the *real-time energy market*, DREBQmk,h = 0; 3. 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*, DREBQmk,h = 0; 4. 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*, DREBQmk,h shall be equal to the lesser of the two *demand response energy bids*; and   Notwithstanding any of the foregoing, DREBQmk,h shall not exceed the CARCmk 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***:**  ∑H(-1) x Max( 0, (CCOmk,h - CAEOmk,h)) x CACPzh x CNPFtm  Where:   1. ‘H’ is the set of all *settlement hours* within the *availability window* during the relevant *trading day*; 2. 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’, CAEOmh,k = 0; 3. If the *energy offer* submitted in the day-ahead commitment process for *settlement hour* ‘h’ is not equal to the *energy offer* submitted in the *pre-dispatch* hour for the same *settlement hour*, CAEOmh,k shall be equal to the lesser of the two *energy offers*; 4. If a *capacity storage resource* receives a non-zero *energy dispatch instruction* within the relevant *availability window,* the CAEOmh,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.* | Daily | Due *IESO* | 13 | 13 | N/A | N/A |  |
| 1320  MRP updated | Capacity Obligation – Dispatch Test Payment and Emergency Activation Payment | CATAPmk,h and CAEOPmk,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 × HDRDCmk,h  **For *emergency operating state* activations:**  Max(0, HDRBP mk,h – Max(0,HOEPh)) × HDRDC mk,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.\*\***  On behalf of the former OPA for the DR2 Program -  Availability Payment Settlement Amount  Where:  ‘CoMW’ (Contracted MW), means the MW specified in the DR2 Schedule(s) for a given Settlement Account which the Participant agrees to Load Shift in each On-Peak Contract hour.  ‘AR’ (Availability Rate), means the availability rate, expressed in $/MW, in the amount as specified by the OPA from time to time on the OPA Website pursuant to the DR2 Program Rules.  ‘H’ is the total On-Peak contract hours in a Contract Month.  ‘ILSR’ (Implied Load Shift Ratio), has the meaning as defined in  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 | 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. |
| 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)**  On behalf of the former OPA for the DR2 Program -   Availability Set-Off Settlement Amount: Reliability  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.  ‘ILSR’ has the same meaning as in CT1330.  **B: Availability Set-Off (Timely Confirmation)**  On behalf of the former OPA for the DR2 Program -   Availability Set-Off Settlement Amount: Reliability: Timely Confirmation  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)**  On behalf of the former OPA for the DR2 Program -   Availability Set-Off Settlement Amount: Reliability: Low Confirmation  This formula applies when the Confirmed MW is less than the product of the Required Reliability Ratio and the Contracted MW for one or more On-Peak Contract hours.  Where:  ‘PSO’ has the same meaning as defined above.  ‘AR’ has the same meaning as in CT1330.  ‘CoMW’ has the same meaning as in CT1330.  ‘CMW’ (Confirmed MW) means the number of MW available to shift by the Participant.  ‘H’ is the set of all confirmed hours ‘h’ when the Confirmed MW’s are:   * Less than 95% during the Summer and Winter seasons or * Less than 90% during the shoulder seasons   of the Contracted MW.  ‘ILSR’ has the same meaning as in CT1330.  **D: Availability Set-Off (Non-Performance)**  On behalf of the former OPA for the DR2 Program -   Availability Set-Off Settlement Amount: Reliability: Non-Performance  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. | 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. |
| 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  On behalf of the former OPA for the DR2 Program -  Utilization Payment Settlement Amount  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:  **A: Utilization Set-Off (Reliability)**  On behalf of the former OPA for the DR2 Program -  Utilization Set-Off Settlement Amount: Reliability  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)**  On behalf of the former OPA for the DR2 Program -  Utilization Set-Off Settlement Amount: Timely Confirmation  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)**  On behalf of the former OPA for the DR2 Program -  Utilization Set-Off Settlement Amount: Low Confirmation  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.  ‘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. | 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. |
| 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 x TDk,1330 / NoWk)  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.   TDk,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. |
| 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 - Miscellaneous Settlement Amount | N/A | N/A | **\*\*CALCULATIONS FOR *CHARGE TYPE* 1336 ENDED ON FEBRUARY 28, 2015.\*\***  Reserved for DR2 payments or charges of a miscellaneous nature not specifically covered under Charge Types 1330 through 1335. | 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. |
| 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.\*\***  = HAH x MCMWh x 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. |
| 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.\*\***  On behalf of the former OPA for the DR3 Program – Availability Over-Delivery Settlement Amt  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)**  On behalf of the former OPA for the DR3 Program – Availability Set-Off Settlement Amount: Reliability  This formula applies when the Reliability Rate for a given Settlement Point is less than 85% during any meter interval of an Activation Hour, or where the Participant is not Fully Available for Curtailment as defined in the *OPA* DR3 Program Rules.  Where:  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)**  On behalf of the former OPA for the DR3 Program – Availability Set-Off Settlement Amount: Timely Confirmation  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.  **C:** **Availability Set-Off (Low Confirmation)**  On behalf of the former OPA for the DR3 Program – Availability Set-Off Settlement Amount: Low  Confirmation  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. | 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. |
| 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.\*\***  On behalf of the former OPA for the DR3 Program – Utilization Payment Settlement Amount  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.  ‘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. | 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. |
| 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)**  On behalf of the former OPA for the DR3 Program – Utilization Set-Off Settlement Amount: Reliability  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)**  On behalf of the former OPA for the DR3 Program – Utilization Set-Off Settlement Amount: Timely Confirmation  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)**  On behalf of the former OPA for the DR3 Program – Utilization Set-Off Settlement Amount: Low Confirmation  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. | 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. |
| 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 x MCMWh x HANEH)  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 x AAR x MCMWh x NEWFH)  Where:  ‘OH’ (Opportunity Hours), means 64 if Option A is applicable to the Settlement Account; or 32 if Option B is applicable to the Settlement Account.  ‘AAR’ has the same meaning as in CT1340.  ‘MCMW’ has the same meaning as in CT1340.  ‘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. | 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. |
| 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 (HAH x MCMWh 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 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. | 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. |
| 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:  ‘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. | 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. |
| 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.\*\***  Demand Response 2 Availability Payment Balancing Amount  Where ‘K’ is the set of all DR2 participants ‘k’.  Where TDk,1330 is the *settlement amount* of *charge type* 1330 for the month for DR2 participant ‘k’. | Monthly | Due *OPA* | 0 | N/A | N/A | N/A | Former *OPA* DR2 Contract. The DR2 program was last settled on the February 2015 *settlement statements* and invoice. |
| 1381 | Demand Response 2 Availability Set-Off Balancing Amount | N/A | N/A | **\*\*CALCULATIONS FOR *CHARGE TYPE* 1381 ENDED ON FEBRUARY 28, 2015.\*\***  Demand Response 2 Availability Set-Off Balancing Amount  Where ‘K’ is the set of all DR2participants ‘k’.  Where TDk,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.\*\***  Demand Response 2 Utilization Payment Balancing Amount  Where ‘K’ is the set of all DR2participants ‘k’.  Where TDk,1332 is the *settlement amount* of *charge type*1332 for the month for DR2 participant ‘k’. | Monthly | Due *OPA* | 0 | N/A | N/A | N/A | Former *OPA* DR2 Contract. The DR2 program was last settled on the February 2015 *settlement statements* and invoice. |
| 1383 | Demand Response 2 Utilization Set-Off Balancing Amount | N/A | N/A | **\*\*CALCULATIONS FOR *CHARGE TYPE* 1383 ENDED ON FEBRUARY 28, 2015.\*\***  Demand Response 2 Utilization Set-Off Balancing Amount  Where ‘K’ is the set of all DR2participants ‘k’.  Where TDk,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.\*\***  Demand Response 2 Meter Data Set-Off Balancing Amount  Where ‘K’ is the set of all DR2participants ‘k’.  Where TDk,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.\*\***  Demand Response 2 Buy-Down  Balancing Amount  Where ‘K’ is the set of all DR2participants ‘k’.  Where TDk,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 statement*s and invoice. |
| 1386 | Demand Response 2 Miscellaneous Balancing Amount | N/A | N/A | **\*\*CALCULATIONS FOR *CHARGE TYPE* 1386 ENDED ON FEBRUARY 28, 2015.\*\***  Demand Response 2 Miscellaneous Balancing Amount  Where ‘K’ is the set of all DR2participants ‘k’.  Where TDk,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.\*\***  Demand Response 3 Availability Payment Balancing Amount  Where ‘K’ is the set of all DR3 participants ‘k’.  Where TDk,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.\*\***  Demand Response 3 Availability Over-Delivery Balancing Amount  Where ‘K’ is the set of all DR3participants ‘k’.  Where TDk,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. |
| 1392 | Demand Response 3 Availability Set-Off Balancing Amount | N/A | N/A | **\*\*CALCULATIONS FOR *CHARGE TYPE* 1392 ENDED ON APRIL 30, 2015.\*\***  Demand Response 3 Availability Set-Off Balancing Amount  Where ‘K’ is the set of all DR3participants ‘k’.  Where TDk,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.\*\***  Demand Response 3 Utilization Payment Balancing Amount  Where ‘K’ is the set of all DR3participants ‘k’.  Where TDk,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.\*\***  Demand Response 3 Utilization Set-Off Balancing Amount  Where ‘K’ is the set of all DR3participants ‘k’.  Where TDk,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. |
| 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.\*\***  Demand Response 3 Planned Non-Event Set-Off Balancing Amount  Where ‘K’ is the set of all DR3participants ‘k’.  Where TDk,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.\*\***  Demand Response 3 Meter Data Set-Off Balancing Amount  Where ‘K’ is the set of all DR3participants ‘k’.  Where TDk,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.\*\***  Demand Response 3   Buy-Down Balancing Amount  Where ‘K’ is the set of all DR3participants ‘k’.  Where TDk,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.\*\***  Demand Response 3  Miscellaneous Balancing Amount  Where ‘K’ is the set of all DR3participants ‘k’.  Where TDk,1348 is the *settlement amount* of *charge type*1348 for the month for DR3 participant ‘k’. | Monthly | Due *OPA* | 0 | N/A | N/A | N/A | Former *OPA* DR3 Contract. The DR3 program was last settled on the April 2015 *settlement statements* and invoice. |
| 1415 | Conservation Assessment Recovery | N/A | N/A | Conservation Assessment Recovery  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 |  |
|  |  |  |  |  |  |  |  |  |  |  |  |
| 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 \*\***  Ontario Clean Energy Benefit (-10%) Program Balancing Amount  Where ‘K’ is the set of all *market participants* ‘k’.  Where TDk,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 \*\***  Ontario Electricity Support Program Balancing 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 *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\*\***  ΣKTDk,1421    Where ‘K’ is the set of all *market participants* ‘k’.  Where TDk,1421 is the total *settlement amount* of *charge type* 1421 for the month for *market participant* ‘k’. | Monthly | Either Way | 0 | N/A | N/A | N/A |  |
| 1472 | Capacity Agreement Penalty Balancing Amount | N/A | N/A | **\*\* CALCULATIONS FOR *CHARGE TYPE* 1472 END DECEMBER 31, 2023 AS PER CONTRACT AGREEMENT\*\***  ΣKTDk,1422    Where ‘K’ is the set of all *market participants* ‘k’.  Where TDk,1422 is the total *settlement amount* of *charge type* 1422 for the month for *market participant* ‘k’. | Monthly | Either way | 0 | N/A | N/A | N/A |  |
| 1473 | Energy Sales Agreement Balancing Amount | N/A | N/A | **\*\* CALCULATIONS FOR *CHARGE TYPE* 1473 END DECEMBER 31, 2023 AS PER CONTRACT AGREEMENT\*\***  ΣKTDk,1423    Where ‘K’ is the set of all *market participants* ‘k’.  Where TDk,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\*\***  ΣKTDk,1424    Where ‘K’ is the set of all *market participants* ‘k’.  Where TDk,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 Component 1 Clawback | DA\_PCG\_COMP1 | 9.4.7D.4 | T (Component 1 – Component1 Clawback)  **Component 1:**  -1 x OP(EMPhm,t, MIN(DA\_DQSIk,hm,t, DQSIk,hm,t, AQEIk,hm,t), DA\_BE) + DA\_SNLCk,hm/12  **Component 1 Clawback:**  -1 x OP(EMPhm,t, MIN(MLPk,hm,t, AQEIk,hm,t), DA\_BE) + DA\_SNLCk,hm/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 x OP(EMPhm,t, MIN(DA\_DQSIk,hm,t, DQSIk,hm,t, AQEIk,hm,t), DIPCk,hm,t) + (DA\_SNLCk,hm/12) \* (1 – PSTk,hp,t)  **Component 1 Clawback:**  -1 x OP(EMPhm,t, MIN(MLP\_CONSk,hm,t, AQEIk,hm,t), DIPCk,hm,t) + (DA\_SNLCk,hm/12) \* (1 – PSTk,hp,t)  For a steam turbine resource associated to a pseudo unit:  **Component 1:**  -1 x OP(EMPhm,t, MIN(DIGQk,hm,t, DQSIk,hm,t, AQEIk,hm,t), DIPCk,hm,t) + (DA\_SNLCk,hm/12) \* PSTk,hp,t  **Component 1 Clawback:**  -1 x OP(EMPhm,t, MIN(MLP\_CONSk,hm,t, AQEIk,hm,t), DIPCk,hm,t) + (DA\_SNLCk,hm/12) \* PSTk,hp,t | Hourly | Either Way | 13 | N/A | N/A | N/A | **Component 1** applies to Variants 1, 2 and 3.  **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 |
| 1501  MRP retired | Day-Ahead Production Cost Guarantee Payment – Component 2 | DA\_PCG\_COMP2 | 9.4.7D.4 | Day-Ahead Production Cost Guarantee Payment – Component 2  Where:  T is the set of metering intervals in the settlement hour h.  XDA\_BEk,hm,t = (-1) \* [OP(EMPhm,t,min(DA\_DQSIk,hm,t, OPCAPk,hm,t), DA\_BE) –  OP(EMPhm,t, min(DA\_DQSIk,hm,t, OPCAPk,hm,t, max(DQSIk,hm,t, AQEIk,hm,t)), DA\_BE)]  XBEk,hm,t = (-1) \* [OP(EMPhm,t,min(DA\_DQSIk,hm,t, OPCAPk,hm,t), BE) –  OP(EMPhm,t, min(DA\_DQSIk,hm,t, OPCAPk,hm,t, max(DQSIk,hm,t, AQEIk,hm,t)), BE)]  Where:  ‘OP’ is the operating profit function defined in *IESO* *market rules* section 9.3.8B.2.    EMPhm,t = 0.  For a combustion turbine and a steam turbine resources associated to a pseudo unit:  DA\_BE is replaced with DIPCk,hm,t.  For a steam turbine resource associated to a pseudo unit:  DA\_DQSIk,hm,t is replaced with the DIGQk,hm,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 |
| 1502  MRP retired | Day-Ahead Production Cost Guarantee Payment – Component 3 and Component 3 Clawback | DA\_PCG\_COMP3 | 9.4.7D.4 | T (-1)\*(Component 3 + 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:   1. DQSI >= MQSI >= DA\_DQSI 2. MQSI >= DQSI >= DA\_DQSI 3. DQSI > DA\_DQSI > MQSI 4. MQSI > DA\_DQSI > DQSI 5. DA\_DQSI >= DQSI > MQSI 6. DA\_DQSI >= MQSI > DQSI   **Component 3:**  Component 3 is calculated when:  the CMSC for energy (TDk,h,105m,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(EMPhm,t, MQSIk,hm,t, BE) – MAX(OP(EMPhm,t, DA\_DQSIk,hm,t, BE), OP(EMPhm,t,AQEIk,hm,t, BE))  Scenario 4:  OP(EMPhm,t, DA\_DQSIk,hm,t, BE) – MAX(OP(EMPhm,t, DQSIk,hm,t, BE), OP(EMPhm,t,AQEIk,hm,t, BE))  Scenario 5 and 6:  TDk,h,105m,t  Refer to Market Rules for a description of Scenarios 1 through 6.  **Component 3 Clawback:**  Component 3 Clawback is calculated when:  the event is a constrained-on event (i.e. Scenarios 3 and 5);  the *minimum loading point* is greater than the real-time unconstrained schedule; and  Component 3 (PCG\_COMP3k,hm,t) for the same interval is a value other than zero.  MAX(OP(EMPhm,t, MLPk,hm,t, BE), OP(EMPhm,t,AQEIk,hm,t, BE)) – OP(EMPhm,t, MQSIk,hm,t, BE)  For combustion turbine resources associated to a pseudo unit:  DA\_BE is replaced with DIPCk,hm,t; and  MLP is replaced with MLP\_CONS.  For steam turbine resources associated to a pseudo unit:  DA\_BE is replaced with DIPCk,hm,t,  MLP is replaced with MLP\_CONS,  and  DA\_DQSIk,hm,t is replaced with the DIGQk,hm,t.  Where  ‘OP’ is the operating profit function defined in *IESO* *market rules* section 9.3.8B.2. | 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 |
| 1503  MRP retired | Day-Ahead Production Cost Guarantee Payment – Component 4 | DA\_PCG\_COMP4 | 9.4.7D.4 | Day-Ahead Production Cost Guarantee Payment – Component 4  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\_SQRORr1,k,hm,t = MAX[0,MIN(DA\_DQSIk,hm,t – MQSIk,hm,t, SQRORr1,k,hm,t)]  10NS\_SQRORr2,k,hm,t = MAX[0,MIN(DA\_DQSIk,hm,t – MQSIk,hm,t - 30R\_SQRORr1,k,hm,t , SQRORr2,k,hm,t)]  10S\_SQRORr3,k,hm,t = MAX[0,MIN(DA\_DQSIk,hm,t – MQSIk,hm,t - 30R\_SQRORr1,k,hm,t – 10NS\_SQRORr2,k,hm,t , SQRORr3,k,hm,t)]  For combustion turbine resources and steam turbine resources associated to a pseudo unit:  DA\_DQSIk,hm,t is replaced with the DIGQk,hm,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 |
| 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\_SUCk,hm  Scenario 2 (achieves MLP between the 7th and 18th interval):  DA\_SUCk,hmDA\_SUCk,hm x 1/12 x 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\_SUCk,hp \* (1 – PSTk,hp,t)  Scenario 2 (achieves MLP between the 7th and 18th interval):  DA\_SUCk,hp \* MLP\_MF \* (1 – PSTk,hp,t)  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\_SUCk,hp \* (PSTk,hp,t)  Scenario 2 (achieves MLP between the 7th and 18th interval):  DA\_SUCk,hp \* MLP\_MF \* (PSTk,hp,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\_SUCk,hm \* 50%  For a combustion turbine resource associated to a pseudo unit:  DA\_SUCk,hm \* (1 – PSTk,hp,t) \* 50%  For a steam turbine resource associated to a pseudo unit:  DA\_SUCk,hm \* (PSTk,hp,t) \* 50% | 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 |
| 1505  MRP retired | Day-Ahead Production Cost Guarantee Reversal |  | 9.4.7D.6 | For each DACP start event  If H,C TDk,h,c < 0  Then H,C TDk,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:  i=1 n (-1) \* OP([MIN(PD\_EMPhm,t, EMPhm,t), MLPk,hm,t, DA\_BEk,hm,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:  i=1 n (-1) \* OP(EMPhm,t, MLPk,hm,t, DA\_BEk,hm,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 DIPCk,hm,t; and the MLP is replaced with MLP\_CONS. | Daily | Due *IESO* | 13 | N/A | N/A | N/A |  |
| 1550  MRP retired | Day-Ahead Production Cost Guarantee Recovery Debit |  | 9.4.8.1.12 | Day-Ahead Production Cost Guarantee Recovery Debit  Where:  'C' is the set of the following charge types 'c' as follows:  **1500, 1501, 1502, 1503, 1504, 1505**  'K' is the set of all market participants 'k'.  'M' is the set of all delivery points 'm' and intertie metering points 'i'.  ‘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 *IESO* | 13 | N/A | 0 | 13 |  |
| 1560  MRP retired | Day-Ahead Generator Withdrawal Rebate |  | 9.4.8.2.14 | Day-Ahead Generator Withdrawal Rebate  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 \*\***  Class A Global Adjustment Deferral Recovery Amount  Where ‘K’ is the set of all *market participants* ‘k’. | Monthly | Due *IESO* | 13 | N/A | N/A | N/A | Ontario Regulation 429/04 |
| 6148 | Class B Global Adjustment Deferral Recovery Amount | N/A | N/A | **\*\* CALCULATIONS FOR *CHARGE TYPE* 6148 END DECEMBER 31, 2021 \*\***  CBRR × CBMzPk  Where:  Class B Global Adjustment Deferral Recovery Amount  Class B Load =  Class B Global Adjustment Deferral Recovery Amount  For Fort Frances Power Corporation Distribution Inc.:  Class B Global Adjustment Deferral Recovery Amount For Fort Frances Power Corporation Distribution Inc  For other applicable Class B *market participants* or licensed *distributors* that are also *market participants*:  Class B Global Adjustment Deferral Recovery Amount for other market participants  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 |
| 9147 | Class A Global Adjustment Smoothing Balancing Amount | N/A | N/A | **\*\* CALCULATIONS FOR *CHARGE TYPE* 9147 END DECEMBER 31, 2021 \*\***  Class A Global Adjustment Smoothing Balancing Amount  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 \*\***  Class B Global Adjustment Smoothing Balancing Amount  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. |

### 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 |
| --- | --- | --- | --- | --- | --- |
| AQORr,k,hm,t | Allocated Quantity of Operating Reserve | 1 | 1 | 1 | * Refer to SQROR. |
| BRr | 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. |
| CAEOmh,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. |
| DA\_BEk,hi,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\_BEk,hm,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\_BLk,hi,t | *Energy* Bidssubmitted 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\_DQSIk,hi,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\_DQSIk,hm,t | *Schedule of record* dispatch quantity scheduled for injection at a *delivery point* | 1 | 1 | 1 | * Not published via upstream *IESO* systems. * Passed to *market participants* via dispatch messaging. |
| DA\_DQSWk,hi,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\_ELMPhm,t | *Pre-dispatch* constrained schedule price for an *intertie metering point* in the export zone | 2 | 2 | 2 | * MIM Publication. |
| DA\_ILMPhm,t | *Pre-dispatch* constrained schedule price for an *intertie metering point* in the import zone | 2 | 2 | 2 | * MIM Publication. |
| DA\_SNLCk,hm | 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\_SNLCk,hp | 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\_SUCk,hm | 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\_SUCk,hp | 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. |
| DIPCk,hm,t | Derived Interval Price Curve | 1 | 2 | 1 | * Derived price curve and therefore not published on *settlement statements.* |
| DIGQk,hm,t | Derived Interval Guaranteed Quantity | 1 | 1 | 1 | * Derived schedule quantity and therefore not published on *settlement statements.* |
| DQSIk,hm,t | Dispatch Quantity of Energy Scheduled for Injection | 1 | 1 | 1 | * Not published via upstream *IESO* systems. * Passed to *market participants* via dispatch messaging. |
| DQSRr,k,hm,t | Dispatch Quantity Schedule of Operating Reserve | 1 | 1 | 1 | * Not published via upstream *IESO* systems*.* * Passed to *market participants* via dispatch messaging. |
| DQSWk,hm,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. |
| DRACPh | Hourly Demand Response Auction Clearing Price | N/A | 2 | 2 | * Not published via upstream *IESO* systems. |
| DRBOCk | Demand Response Buy-Out Capacity | N/A | 3 | 3 | * Not published via upstream *IESO* systems. |
| DRCOk | Demand Response Capacity Obligation (MW) | 1 | 3 | 3 | * Published in private post-auction report. |
| DREBQk | 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. |
| EIMk,h | Operating Profit Function for the IMPORT of Energy under the Intertie Offer/Bid Guarantee Settlement Credit | N/A  Refer to [section 3.4](#_Rounding_Conventions_–_1) | N/A  Refer to [section 3.4](#_Rounding_Conventions_–_1) | N/A  Refer to [section 3.4](#_Rounding_Conventions_–_1) | * This acronym is associated with the energy import component of the Intertie Offer/Bid Guarantee Settlement Credit. |
| EMPhi,t | 5-minute Energy Market Price at the Interties | 2 | 2 | 2 | * MIM Publication. |
| EMPhm,t | 5-minute Energy Market Price within Ontario | 2 | 2 | 2 | * MIM Publication. |
| EMPhREF,t | 5-minute Energy Market Reference Price | 2 | 2 | 2 | * MIM Publication. |
| FPhm | Fixed Energy Rate | N/A | 2 | 2 | * Not published via upstream *IESO* systems. |
| FPChm | 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. |
| HOEPh | Hourly Ontario Energy Price | 2 | 2 | 2 | * MIM Publication. |
| MAX\_CAPk,hm,t | Maximum Capacity | 2 | 3 | 3 |  |
| MChm | 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.* |
| MLPk,hm,t | Minimum Loading Point | 1 | 1 | 1 | * Not published via upstream *IESO* systems. |
| MLP\_CONSk,hm,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. |
| MQSIk,hm,t | Market Quantity Scheduled for Injection | 1 | 1 | 1 |  |
| MQSI{adj}k,hm,t | Adjusted Market Quantity Scheduled for Injection | 1 | 1 | 1 | * Derived variable and therefore not published on *settlement statements.* |
| MQSWk,hm,t | Market Quantity Scheduled for Withdrawal | 1 | 1 | 1 |  |
| OP | Operating Profit Function | N/A  Refer to [section 3.4](#_Rounding_Conventions_–_1) | N/A  Refer to [section 3.4](#_Rounding_Conventions_–_1) | N/A  Refer to [section 3.4](#_Rounding_Conventions_–_1) | * This acronym is associated with the operating profit equation used within the CMSC equation. |
| OPCAPk,hm,t | Operating Capacity | 1 | 1 | 1 | * Not published via upstream *IESO* systems. |
| PD\_BEk,hi,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\_BLk,hi,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\_DQSIk,hi,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\_DQSWk,hi,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\_ELMPhm,t | *Pre-dispatch* constrained schedule price for an *intertie metering point* in the export zone | 2 | 2 | 2 | * MIM Publication. |
| PD\_EMPhm,t | Pre-dispatchenergy market price for Ontario | 2 | 2 | 2 | * MIM Publication. |
| PD\_ILMPhm,t | *Pre-dispatch* constrained schedule price for an *intertie metering point* in the import zone | 2 | 2 | 2 | * MIM Publication. |
| SQEIk,hi,t | Scheduled Quantity of Energy Injected at an *intertie metering point* | 1 | 1 | 1 |  |
| SQEWk,hi,t | Scheduled Quantity of Energy Withdrawn at an *intertie metering point* | 1 | 1 | 1 |  |
| SQRORr,k,hm,t | Scheduled Quantity of class r *Operating Reserve* | 1 | 1 | 1 |  |

### Rounding Conventions – by Charge Type

Refer to [section 2.3](#_Toc270932499) 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  (EMPhj,t – EMP hi,t)  Denominator: 12  Resulting Decimals: 5 | Multiplied by QTR for the *settlement hour.* |  |  |
| 105 | Congestion Management Settlement Credit for Energy | 1 | 3 | Yes | AQEI multiplied by 12 or  AQEW multiplied by 12  Resulting Decimals: 3 | Used in the calculation of OP(EMP, AQEI, BE) or OP(EMP, AQEW, BL) as the case may be. | Numerators  OP(EMP, MQSI, BE)  OP(EMP, DQSI, BE)  OP(EMP, AQEI, BE)  OP(EMP, MQSW, BL)  OP(EMP, DQSW, BL)  OP(EMP, AQEW, BL)  Denominator: 12  Resulting Decimals: 2 | Profits compared as applicable. |
| 106 | Congestion Management Settlement Credit for 10 Minute Spinning Reserve | 1 | 2 | Yes | Numerators  OP(PROR, MQSR, BR)  OP(PROR, DQSR, BR)  OP(PROR, AQOR, BR)  Denominator: 12  Resulting Decimals: 2 | Profits compared as applicable. |  |  |
| 107 | Congestion Management Settlement Credit for 10 Minute Non-spinning Reserve | 1 | 2 | Yes | Numerators  OP(PROR, MQSR, BR)  OP(PROR, DQSR, BR)  OP(PROR, AQOR, BR)  Denominator: 12  Resulting Decimals: 2 | Profits compared as applicable. |  |  |
| 108 | Congestion Management Settlement Credit for 30 Minute Operating Reserve | 1 | 2 | Yes | Numerators  OP(PROR, MQSR, BR)  OP(PROR, DQSR, BR)  OP(PROR, AQOR, BR)  Denominator: 12  Resulting Decimals: 2 | Profits compared as applicable. |  |  |
| 111 | Northern Pulp and Paper Mill Electricity Transition Program Settlement Amount | 1 | 3 | No |  |  |  |  |
| 112 | Ontario Power Generation Rebate | 2 | 3 | No |  |  |  |  |
| 113 | Additional Compensation for Administrative Pricing Credit | 1 | 3 | Yes | For the calculation outlined in 7.8.4A.16 only:  for dispatchable *facilities* located within Ontario only  AQEI multiplied by 12 or  AQEW multiplied by 12  Resulting Decimals: 3 | (For the calculation outlined in 7.8.4A.16 only)  For dispatchable *facilities* located within Ontario only:  Used in the calculation of OP(EMP, AQEI, BE) or OP(EMP, AQEW, BL) as the case may be. | For the calculation outlined in 7.8.4A.16 only:  Numerators:  for dispatchable *facilities* located within Ontario:  OP(EMP, AQEI, BE)  OP(EMP, AQEW, BL)  for Imports or Exports:  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 |  |  |  |  |
| 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 |  |  |  |  |
| 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 |  |  |  |  |
| 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 |  |  |  |  |
| 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 |  |  |  |  |
| 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 |  |  |  |  |
| 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. |  |  |
| 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. |  |  |
| 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)  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 | **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. |  |  |
| 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,  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 | TERM 1, TERM 2 and  TERM 3 compared as  applicable. |  |  |
| 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 |  |  |  |  |
| 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 |  |  |  |  |
| 1193 | Ontario Fair Hydro Plan Eligible Non-RPP Consumer Discount Balancing Amount | 2 | 2 | No |  |  |  |  |
| 1194 | Ontario Fair Hydro Plan Financing Entity Balancing Amount | 2 | 2 | No |  |  |  |  |
| 1195 | Ontario Fair Hydro Plan Financing Entity Balancing Interest | 2 | 2 | No |  |  |  |  |
| 1300 | Capacity Based Demand Response Program Availability Payment Settlement Amount | 1 | 3 | No |  |  |  |  |
| 1301 | Capacity Based Demand Response Program Availability Over-Delivery Settlement Amt | 1 | 3 | No |  |  |  |  |
| 1302 | Capacity Based Demand Response Program 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 |  |  |  |  |
| 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 |  |  |  |  |
| 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 |  |  |  |  |
| 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 |  |  |  |  |
| 1341 | On behalf of *Former* OPA for the DR3 Program – Availability Over-Delivery Settlement Amt | 1 | 3 | No |  |  |  |  |
| 1342 | On behalf of *Former* OPA for the DR3 Program – Availability Set-Off Settlement Amount | 1 | 3 | No |  |  |  |  |
| 1343 | On behalf of *Former* OPA for the DR3 Program – Utilization Payment Settlement Amount | 1 | 3 | No |  |  |  |  |
| 1344 | On behalf of *Former* OPA for the DR3 Program – Utilization Set-Off Settlement Amount | 1 | 3 | No |  |  |  |  |
| 1345 | On behalf of *Former* OPA for the DR3 Program – Planned Non-Performance Event Set-Off Amt | 1 | 3 | No |  |  |  |  |
| 1346 | On behalf of *Former* OPA for the DR3 Program – Meter Data Set-Off Settlement Amount | 1 | 3 | No |  |  |  |  |
| 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 |  |  |  |  |
| 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 |  |  |  |  |
| 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 |  |  |  |  |
| 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 |  |  |  |  |
| 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),  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. | Profits are compared as applicable. |
| 1501 | Day-Ahead Production Cost Guarantee Payment – Component 2 | 1 | 3 | Yes | AQEI is multiplied by 12  Resulting decimal: 3 | Use in the calculation of OP(EMP,AQEI, DA\_BE),  OP(EMP,AQEI, BE) | **For each 5 minute metering interval:**  Numerator  OP(EMP,AQEI, DA\_BE),  OP(EMP,DQSI, DA\_BE),  OP(EMP,DA\_DQSI, DA\_BE)  OP(EMP,OPCAP, DA\_BE)  OP(EMP,AQEI, BE),  OP(EMP,DQSI, BE),  OP(EMP,DA\_DQSI, BE)  OP(EMP,OPCAP, BE)  Resulting Decimal: 2 | Profits are compared as applicable. |
| 1502 | Day-Ahead Production Cost Guarantee Payment – Component 3 and Component 3 Clawback | 1 | 3 | Yes | AQEI is multiplied by 12  Resulting decimal: 3 | Use in the calculation of  OP(EMP,AQEI, BE), | **For each 5 minute metering interval:**  Numerator  OP(EMP,AQEI, BE),  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. |
| 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 |  |  |  |  |
| 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 |  |  |  |  |
| 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 |  |  |  |  |

### Settlement of Physical Bilateral Contracts

#### 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* (BCQk,b,hm,t) or a *Physical Bilateral Contract Quantity of Energy Bought* (BCQs,k,hm,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](#_Variable_Descriptions_1) and *charge type* described in [section 3.2](#_Toc140737042) 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 (BCQk,b,hm,t) at the 5-Minute Energy Market Price within Ontario (EMPhm,t). | * Credit the Physical Bilateral Contract Quantity of Energy Bought (BCQs,k,hm,t) at the *Hourly Ontario Energy Price* (HOEP). | 101 |
| Dispatchable *delivery point* | * Debit the Physical Bilateral Contract Quantity of Energy Sold (BCQk,b,hm,t) at the 5-Minute Energy Market Price within Ontario (EMPhm,t). | * Credit the Physical Bilateral Contract Quantity of Energy Bought (BCQs,k,hm,t) at the 5-Minute Energy Market Price within Ontario (EMPhm,t). | 100 |
| *Intertie Metering Point* | * Debit the Physical Bilateral Contract Quantity of Energy Sold (BCQk,b,hm,t) at the 5-minute Energy Market Price at the *Interties* (EMPhi,t). | * Credit the Physical Bilateral Contract Quantity of Energy Bought (BCQs,k,hm,t) at the 5-minute Energy Market Price at the *Interties* (EMPhi,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](#_Toc140737042).

#### The Nature of the Bilateral Contract Quantity

Table 3‑6: Bilateral Contract Quantities

| Variable | Name | Description |
| --- | --- | --- |
| **BCQs,k,hm,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’. |
| **BCQk,b,hm,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](#_Time_Resolution_of) 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](#_Time_Resolution_of) 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](#_Time_Resolution_of) 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](#_Time_Resolution_of) FOR THE DATA PRESENTATION OF THE BILATERAL CONTRACT QUANTITY) | | | | | | | | | | | |

#### 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](#_Rounding_Conventions_–_1) 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](#_Rounding_Conventions_–_1) 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? |
| --- | --- | --- | --- | --- | --- |
| **BCQs,k,hm,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](#_Rounding_Conventions_–_1) |
| 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](#_Rounding_Conventions_–_1) |
| **BCQk,b,hm,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](#_Rounding_Conventions_–_1) |
| Non-Dispatchable *Delivery Point* (injection or withdrawal sub-type) | 101 | by *metering interval* | Yes – Refer to [section 3.4](#_Rounding_Conventions_–_1) |
| *Intertie metering point* | 100 | by *metering interval* | Yes – Refer to [section 3.4](#_Rounding_Conventions_–_1) |

#### 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 UpliftComponent (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 (EMPhREF,t) for each *metering interval* in the *settlement hour*. |
| *Operating Reserve* Settlement Credit (ORSC) Hourly UpliftComponent | 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 UpliftComponent | 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 UpliftComponent | 155 | * Includes recovery of CMSC payments for *energy* and each class of *operating reserve.* |
| Transmission Rights Settlement Credit (TRSC) Hourly UpliftComponent | NOT USED | * INCLUDED WITH THE “NET ENERGY MARKET SETTLEMENT CREDIT (NEMSC) Hourly UpliftCOMPONENT”. * REFER TO NOTE ABOVE. |
| Transmission Charge Reduction Fund (TCRF) Hourly UpliftComponent | NOT USED | * INCLUDED WITH THE “NET ENERGY MARKET SETTLEMENT CREDIT (NEMSC) Hourly UpliftCOMPONENT”. * REFER TO NOTE ABOVE. |
| Operating Reserve Shortfall Settlement Debit (ORSSD) Hourly UpliftComponent | 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,hm,t =s,b [BCQk,b,hm,t - BCQs,k,hm,t]

Where all variables are defined as per [section3.1](#_Variable_Descriptions_1).

The RQ quantity is then used to either augment or decrease the *settlement amount* for the hourly uplift *charge type* “c” as follows:

cM,T TDk,h,c x [(AQEWk,hm,t + SQEW k,hi,t + RQk,hm,t) / kM,T (AQEWk,hm,t + SQEWk,hi,t)]

Where all variables are defined as per [section3.1](#_Variable_Descriptions_1).

In the event that the term,

(AQEWk,hm,t + SQEW k,hi,t + RQk,hm,t) < 0

Where:

RQk,hm,t < 0 and **|**RQk,hm,t**|** > **|**(AQEWk,hm,t + SQEW k,hi,t)**|** and TDk,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**](#_Toc140737042) **for specific listings of *charge types* and their respective equations.**

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

#### 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]](#footnote-5).

Generally speaking the applicability of the five Intertie Failure charges[[5]](#footnote-6) 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.

#### 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.

#### 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.

#### Input Data:

|  |  |  |
| --- | --- | --- |
| DA\_DQSIk,hi,t | = | Day-aheadconstrained quantity scheduled for injection by *market participant* ‘k’ at *intertie metering point* ‘i’ during *metering interval* ‘t’ of *settlement hour* ‘h’ |
| PD\_DQSIk,hi,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\_BEk,hi,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\_DQSWk,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\_DQSWk,hi,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\_BLk,hi,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*. |

#### 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 (DA\_DQSIk,hi,t) for the import transaction is indeed GREATER THAN the resulting *Pre-dispatch schedule* (PD\_DQSIk,hi,t) over the course of *settlement hour* ‘h’.

IF ∑T DA\_DQSIk,hi,t  > ∑T PD\_DQSIk,hi,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\_BEk,hi,t (refer to above for definition).

IF B[2,2] ≥ DA\_DQSIk,hi,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).

#### 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\_DQSWk,hi,t) for the export transaction is indeed GREATER THAN the resulting *Pre-dispatch schedule* (PD\_DQSWk,hi,t) over the course of *settlement hour* ‘h’.

IF ∑T DA\_DQSWk,hi,t  > ∑T PD\_DQSWk,hi,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 BLk,hi,t (refer to above for definition)

IF B[2,2] ≥ DA\_DQSWk,hi,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).

#### 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\_BEk,hi,t (refer to above for definition).

IF B[2,2] ≥ DA\_DQSIk,hi,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 BLk,hi,t (refer to above for definition).

IF B[2,2] ≥ DA\_DQSWk,hi,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**.

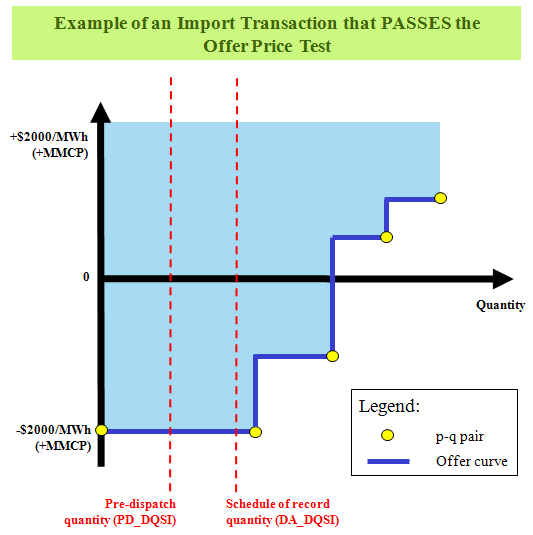


Figure 3‑1: Example of an Import Transaction that PASSES the “Offer Price Test”

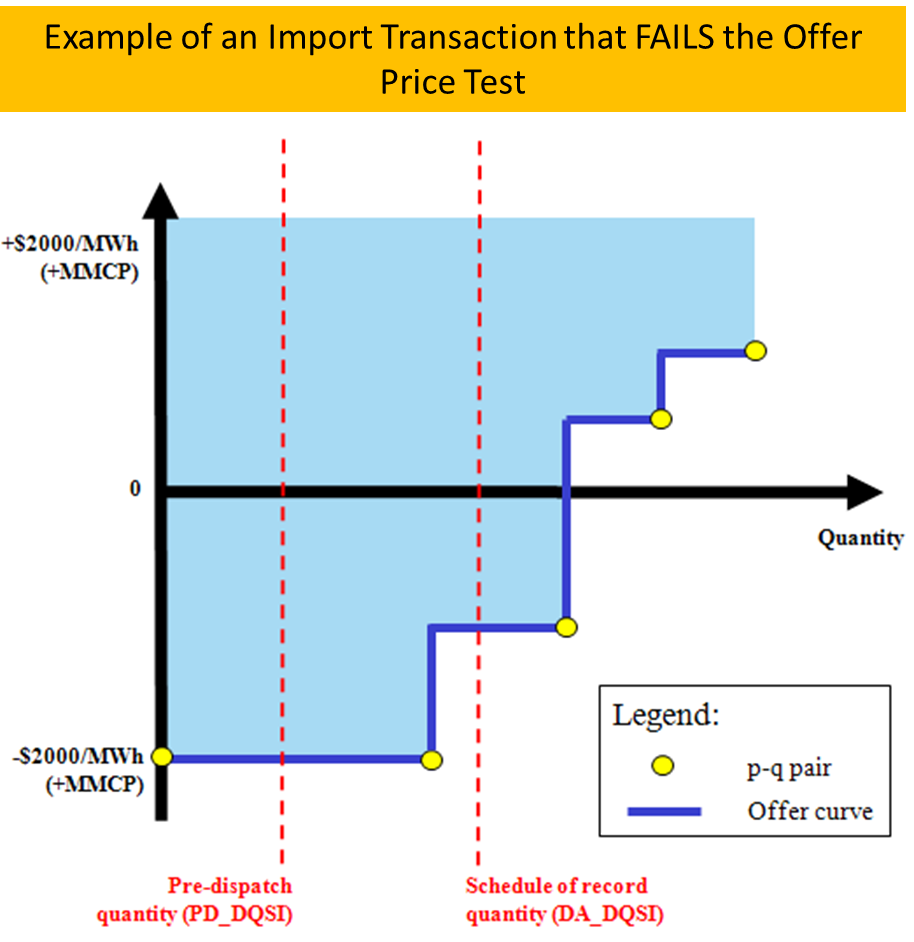


Figure 3‑2: Example of an Import Transaction that FAILS the “Offer Price Test”

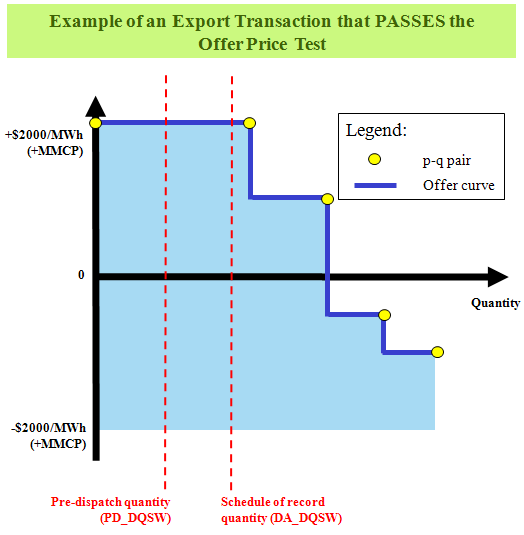


Figure 3‑3: Example of an Export Transaction that PASSES the “Offer Price Test”

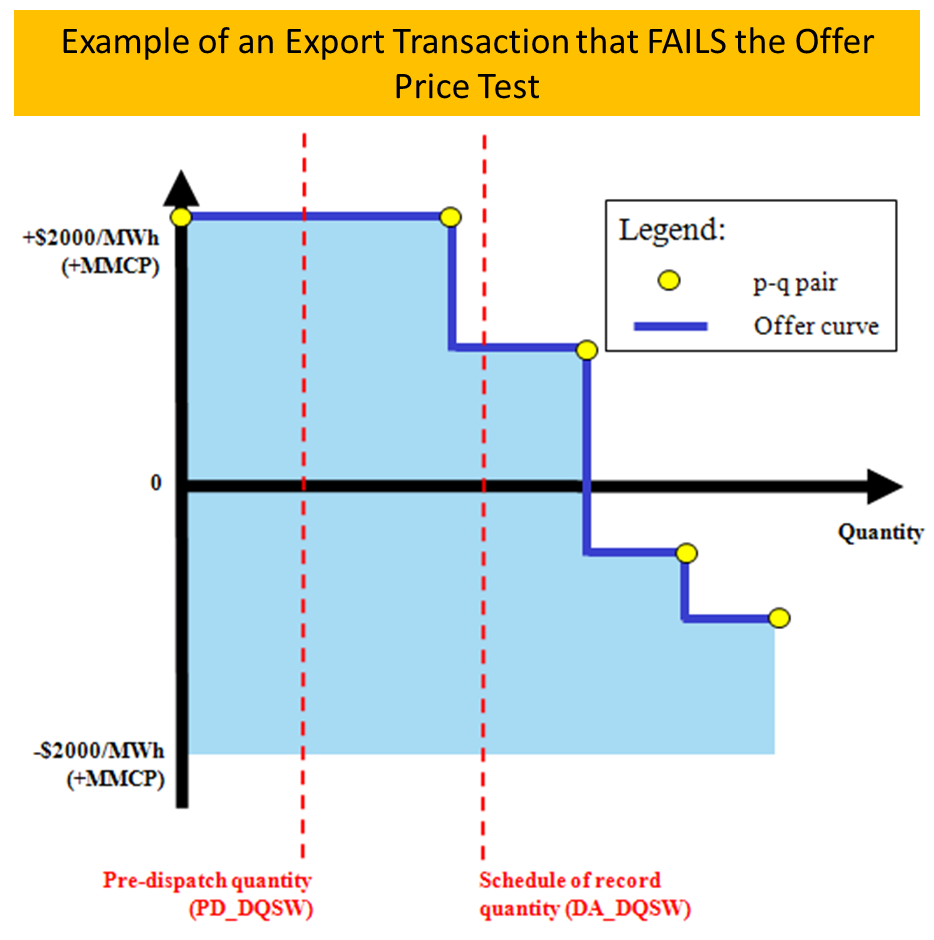


Figure 3‑4: Example of an Export Transaction that PASSES the “Offer Price Test”

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 |

– End of Document –

1. Refer to **MM 1.5** <https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/imrm/MM-1-5-market-registration-procedures-20220909.ashx>for adding and updating contact roles with the *IESO*. [↑](#footnote-ref-2)
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](https://www.ieso.ca/-/media/Files/IESO/Document-Library/Market-Rules-and-Manuals-Library/market-manuals/settlements/se-StatementAndDataFileFormatSpec.ashx). [↑](#footnote-ref-3)
3. *Market Rules* ref.: Section 3.6.2 of Chapter 9. [↑](#footnote-ref-4)
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. [↑](#footnote-ref-5)
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). [↑](#footnote-ref-6)