PUBLIC

PROCEDURE

Market Manual 5: Settlements

Part 5.5: IESO-Administered Markets Settlement Amounts

Issue 86.1

December 1, 2022

This *market manual* is provided for stakeholder engagement purposes. Please note that additional changes to this document may be incorporated as part of future engagement in MRP or other *IESO* activities prior to this *market manual* taking effect.

This procedure describes the *settlement amounts* associated with the *IESO-administered markets*.

MDP_PRO_0033

Document Change History

Issue	Reason for Issue	Date
This version of MM 5.5 contains new content to reflect the *settlement process* under the Market Renewal Program (MRP). The previous version of MM 5.5 will be obsolete post-MRP. For history prior to MRP, refer to version 86.0 and prior.		
86.1	Updated and repurposed to reflect how *settlement amounts* associated with the *IESO-administered markets* are determined.	December 1, 2022

Related Documents

Document ID	Document Title

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Reference	Description of Change
New Document	"Batch 4" changes for Market Renewal Program, reflecting design elements in the following detailed design documents: • Market Settlements & Metering • Market Billing and Funds Administration Document name change

Conventions

The standard conventions followed 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;
- Data fields are identified in all capitals.

– End of Section –

1 Introduction

1.1 Purpose

This *market manual* provides administrative and procedural details to the *market rules* governing the *settlement process,* including supplementary information relevant to understanding the rights and obligations of the *IESO* and *market participants*.

Market manuals must be read in conjunction with the applicable *market rules*. Where there is a conflict between a *market manual* and the *market rules*, the *market rules* shall prevail.

1.2 Scope

This *market manual* supplements the following *market rules*:

- MR Ch.3 s.2.7
- MR Ch.7 s.7.5.8B, s.8.4A and s.22.5.11
- MR Ch.8 ss.3.18-3.19
- MR Ch.9 s.1: Introductory Rules
- MR Ch.9 s.2: Settlement Data Collection and Management
- MR Ch.9 s.3: Hourly Settlement Amounts
- MR Ch.9 s.4: Non-Hourly Settlement Amounts
- MR Ch.9 s.5: Market Power Mitigation
- MR Ch.9 s.6: Settlement Statements

This *market manual* also includes a listing of each hourly and non-hourly *settlement amount* by *charge type* that will appear on a *market participant's settlement statement* and *invoice.*

For *settlement amounts* not associated with the *IESO-administered markets,* which include, but are not limited to those as directed by *applicable law*, refer to MM 5.6: Non-Market Settlement Programs.

1.3 Overview

The following markets form the *IESO-administered markets*:

Table 1-1: IESO-Administered Markets

Market Type	Transactions
Physical Market	1. *Day-Ahead Market* a. *energy* transactions b. *operating reserve* transactions 2. *Real-Time Market* a. *energy* transactions b. *operating reserve* transactions 3. *Procurement Market* a. *contracted ancillary services*, including *regulation, voltage control* and *reactive support services, black-start capability*, and for *reliability must-run contracts* 4. Payments to *TR holders*[1] 5. *Virtual Transactions*[2]
Financial Market	1. *Transmission Rights Market (TR Market*) a. Transactions in all rounds of any *TR auction*[3]

For the tax treatment of the *settlement amounts* in this *market manual*, refer to IESO Charge Types and Equations.

The general principles of financial neutrality for the *physical market* are set out in MR Ch.9 s.6.18. The *physical market* will be financially balanced (net neutral) each month.

The financial *TR market* is self-funding and cannot be financially balanced each month. Refer to MR Ch.8 ss.3.18-3.19 for further details.

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[1] Excludes *settlement amounts* relating to transactions in all rounds of any *TR auction* which will appear on the financial market *settlement statement* and *invoice*.

[2] *Virtual transactions*, although part of the financial market, will be *settled* as part of the *physical market* and will appear on the *physical market* preliminary and *final settlement statements* and *invoices*.

[3] For more information on the *TR auction* process, refer to MM 4.4: Transmission Rights Auction. Only those *settlement amounts* relating to transactions in all rounds of any *TR auction* will appear on the financial market *settlement statement*.

1.4 Contact Information

Changes to this *market manual* are managed via the [*IESO* Change Management process]. Stakeholders are encouraged to participate in the evolution of this *market manual* via this process.

As part of the authorization and registration process[4], *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 for activities within this procedure, unless alternative arrangements have been established between the *IESO* and the *market participant*.

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

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

– End of Section –

[4] Refer to MM 1.5: Market Registration Procedures for adding and updating contact roles with the *IESO*.

2 Day-Ahead Market and Real-Time Market Settlement Charges, Credits and Uplifts

2.1 Two-Settlement System

(MR Ch.9 s.3.1)

The *settlement* of the *day-ahead market* and *real-time market* for *energy* and *operating reserve* will be accomplished through the two-*settlement* system for *dispatchable resources.*

The two-*settlement* system, as described in MR Ch.9 s.3.1, includes a *day-ahead market settlement* and a real-time balancing *settlement*. *Settlement amounts* from each include the following:

- **Day-ahead market settlement** includes *settlement amounts* for *energy* and *operating reserve* that can be completely calculated on the basis of *settlement*-ready data from the *day-ahead market calculation engine*. The *IESO* pays or charges *market participants* the *day-ahead scheduled* quantity for *energy* and *operating reserve* at the applicable *day-ahead market locational marginal price*.
- **Real-time balancing settlement** includes *settlement amounts* that can be calculated on the basis of *settlement*-ready data from the *day-ahead market calculation engine*, reconciled with the *real-time market* results. It balances any deviations between the *day-ahead market* and the *real-time market*. The *IESO* pays or charges *market participants* at the applicable *real-time market locational marginal price* if the actual *energy* consumed or produced, or *operating reserve offered*, differs from the *day-ahead scheduled* quantity.

The *settlement amounts* calculated under both the *day-ahead market settlement* and the real-time balancing *settlement* for *virtual transactions* and *physical transactions* will be provided to *market participants* via *preliminary settlement statements* and *final settlement statements.*

2.1.1 Hourly Physical Transaction Settlement Amount (HPTSA)

(MR Ch.9 ss.3.1.2-3.1.7)

As described in MR Ch.9 ss.3.1.2 to 3.1.7, the *settlement* of the *day-ahead market* and *real-time market* for *energy* will be accomplished through the Hourly Physical Transaction Settlement Amount (HPTSA), where:

- the HPTSA is applicable to all *dispatchable resources* that have a *day-ahead schedule* for *energy*;

- the *day-ahead market settlement* (HPTSA{1}) establishes a *market participant's* position for *energy* in the *day-ahead market*; and
- the real-time balancing *settlement* (HPTSA{2}) reconciles the difference between a *market participant's* position for *energy* in the *day-ahead market* and their actual *real-time market* activity.

The sum of the *day-ahead market settlement* (HPTSA{1}) and the real-time balancing *settlement* (HPTSA{2}) will establish a *market participant's* net *energy* position.

Where applicable, the following *settlement amounts* will be included in the *market participant's* net *energy* position as captured in each of the *energy charge types* below:

- *day-ahead market settlement* of *physical bilateral contracts* (PBCs*)* (HPTSA_PBC{1}); and
- real-time balancing *settlement* of *physical bilateral contracts* (HPTSA_PBC{2}).

Refer to MM 5.3: Physical Bilateral Contract Data for further information on *physical bilateral contracts*.

The following table lists the HPTSA *settlement amounts* on the basis of the *dispatchable resource* type*.*

Table 2-1: Hourly Physical Transaction Settlement Amounts

Dispatchable Resource Type	DAM Settlement Charge Type	Real-Time Balancing Settlement Charge Type
Dispatchable generator	*Charge type* 1100 Day-Ahead Market Energy Settlement Amount for Dispatchable Generators	*Charge type* 1101 Real-Time Energy Settlement Amount for Dispatchable Generators
Dispatchable load	*Charge type* 1102 Day-Ahead Market Energy Settlement Amount for Dispatchable Loads	*Charge type* 1103 Real-Time Energy Settlement Amount for Dispatchable Loads
Price responsive load[5]	*Charge type* 1104 Day-Ahead Market Energy Settlement Amount for Price Responsive Loads	*Charge type* 1105 Real-Time Energy Settlement Amount for Price Responsive Loads

[5] *Price responsive loads* can be inclusive of physical *hourly demand response resources* (HDRs). The *settlement* of both will be combined and will appear under the *price responsive load*. Both the PRL and the physical HDR must have the same *metered market participant*.

Dispatchable Resource Type	DAM Settlement Charge Type	Real-Time Balancing Settlement Charge Type
Boundary entity resource – import	*Charge type* 1110 Day-Ahead Market Energy Settlement Amount for Imports	*Charge type* 1111 Real-Time Energy Settlement Amount for Imports
Boundary entity resource – export	*Charge type* 1112 Day-Ahead Market Energy Settlement Amount for Exports	*Charge type* 1113 Real-Time Energy Settlement Amount for Exports

2.1.2 Hourly Virtual Transaction Settlement Amount (HVTSA)

(MR Ch.9 ss.3.1.8-3.1.9)

As described in MR Ch.9 ss.3.1.8 to 3.1.9, the *settlement* of *energy* for *virtual transactions* in both the *day-ahead market* and *real-time market* will be accomplished through the Hourly Virtual Transaction Settlement Amount (HVTSA), where:

- the HVTSA is applicable to all *virtual zonal resources* that have a *day-ahead schedule*;
- the *day-ahead market settlement* (HVTSA{1}) establishes a *market participant's virtual transaction* for *energy* position in the *day-ahead market*; and
- the real-time balancing *settlement* (HVTSA{2}) reflects any price differences between the *day-ahead market settlement* and the real-time balancing *settlement*.

The sum of the *day-ahead market settlement* (HVTSA{1}) and the real-time balancing *settlement* (HVTSA{2}), will establish a *market participant's* net *energy* position. Specifically, the *settlement* of the *virtual transaction* will be based on the *energy* price difference between the *day-ahead market* and the *real-time market*.

The following table lists the HVTSA *settlement amounts* on the basis of the *virtual transaction* type involved.

Table 2-2: Hourly Virtual Transaction Settlement Amounts

Virtual Transaction Type	DAM Settlement Charge Type	Real-Time Balancing Settlement Charge Type
Virtual transaction to sell *energy* (i.e. *day-ahead schedule* to inject)	*Charge type* 1106 Day-Ahead Market Energy Settlement Amount for Virtual Transactions to Sell	*Charge type* 1107 Real-Time Energy Settlement Amount for Virtual Transactions to Sell

Virtual Transaction Type	DAM Settlement Charge Type	Real-Time Balancing Settlement Charge Type
Virtual transaction to buy *energy* (i.e. *day-ahead schedule* to withdraw)	*Charge type* 1108 Day-Ahead Market Energy Settlement Amount for Virtual Transactions to Buy	*Charge type* 1109 Real-Time Energy Settlement Amount for Virtual Transactions to Buy

2.1.3 Hourly Operating Reserve Settlement Amount (HORSA)

(MR Ch.9 ss.3.1.10-3.1.11)

As described in MR. Ch.9 ss.3.1.10 to 3.1.11, the *settlement* of the *day-ahead market* and *real-time market* for *operating reserve* will be accomplished through the Hourly Operating Reserve Settlement Amount (HORSA), where:

- the HORSA is applicable to all *dispatchable resources* that have a *day-ahead schedule* for *operating reserve*;
- the *day-ahead market settlement* (HORSA{1}) establishes a *market participant's* position for *operating reserve* in the *day-ahead market*; and
- the real-time balancing *settlement* (HORSA{2}) reconciles the difference between a *market participant's* position for *operating reserve* in the *day-ahead market* and their actual *real-time market* activity.

The sum of the *day-ahead market settlement* (HORSA{1}) and the real-time balancing *settlement* (HORSA{2}) will establish a *market participant's* net *operating reserve* position.

The following table lists the HORSA *settlement amounts* on the basis of the type of *class r reserve*.

Table 2-3: Hourly Operating Reserve Settlement Amounts

Class r Reserve Type	Day-Ahead Market Settlement Charge Type	Real-Time Balancing Settlement Charge Type
Spinning *ten-minute operating reserve*	*Charge type* 212 Day-Ahead Market 10-Minute Spinning Reserve Settlement Credit	*Charge type* 213 Real-Time 10-Minute Spinning Reserve Settlement Credit
Non-spinning *ten-minute operating reserve*	*Charge type* 214 Day-Ahead Market 10-Minute Non-Spinning Reserve Settlement Credit	*Charge type* 215 Real-Time 10-Minute Non-Spinning Reserve Settlement Credit

Class r Reserve Type	Day-Ahead Market Settlement Charge Type	Real-Time Balancing Settlement Charge Type
Thirty-minute operating reserve	*Charge type* 216 Day-Ahead Market 30-Minute Operating Reserve Settlement Credit	*Charge type* 217 Real-Time 30-Minute Operating Reserve Settlement Credit

2.1.3.1 Hourly Uplift of HORSA

(MR Ch.9 s.3.10)

The cumulative amount of all HORSA incurred in the *day-ahead market* and the *real-time market* will be allocated as part of the *hourly uplift.*

The *IESO* will determine a *settlement amount* under the following *charge types.*

Table 2-4: Hourly Uplift of HORSA

Charge Type Number	Charge Type Name
250	10-Minute Spinning Reserve Hourly Uplift
252	10-Minute Non-Spinning Reserve Hourly Uplift
254	30 Minute Operating Reserve Hourly Uplift

2.2 Non-Dispatchable Resource Settlement

(MR Ch.9 s.3.2)

As described in MR Ch.9 s.3.2, the *settlement* of *energy* for *non-dispatchable resources* will be based on the actual quantity of *energy* withdrawn or injected in the *real-time market*.

2.2.1 Non-Dispatchable Generators (HPTSA_NDG)

(MR Ch.9 s.3.2.4)

As described in MR Ch.9 s.3.2.4, the *settlement* of *energy* for *non-dispatchable generation resources* will be accomplished through the Hourly Physical Transaction Settlement Amount for *non-dispatchable generation resources*. The *settlement amount* will be based on the actual quantity of *energy* injected at the *delivery point* multiplied by the applicable *real-time market locational marginal price.*

The *IESO* will determine a *settlement amount* under the following *charge type.*

Table 2-5: Non-Dispatchable Generator Energy Settlement Amount

Charge Type Number	Charge Type Name
1114	Non-Dispatchable Generator Energy Settlement Amount

2.2.2 Non-Dispatchable Loads (HPTSA_NDL)

(MR Ch.9 ss.3.2.1-3.2.3)

As described in MR Ch.9 ss.3.2.1-3.2.3, the *settlement* of *energy* for *non-dispatchable loads* will be accomplished through the Hourly Physical Transaction Settlement Amount for *non-dispatchable loads.* As *non-dispatchable loads* do not have a *day-ahead market* position, the *settlement* of *energy* is based on the *day-ahead market Ontario zonal price* adjusted by the load forecast deviation charge, and the actual quantity of *energy* withdrawn at the *delivery point* in real-time by the *non-dispatchable load.*

When there is a *day-ahead market* failure or a suspension of the *day-ahead market*, s*ettlement* of *non-dispatchable loads* will be based on the *real-time market Ontario zonal price,* as described in MR Ch.9 s.2.14.2.

The *IESO* will determine a *settlement amount* under the following *charge type*.

Table 2-6: Non-Dispatchable Load Energy Settlement Amount

Charge Type Number	Charge Type Name
1115	Non-Dispatchable Load Energy Settlement Amount

2.2.2.1 Load Forecast Deviation Charge

(MR Ch.9 s.3.2.3)

The purpose of the load forecast deviation charge is to account for the cost impacts of difference in forecasted demand and actual demand of *non-dispatchable loads.* In accordance with MR App.7.5 s.6.3.1, the *IESO* will forecast load *demand* for *non-dispatchable loads* in the *day-ahead market*. Load forecast deviations occur when the *IESO* forecast *demand* for *non-dispatchable loads* in the *day-ahead market* differs from the actual quantity of *energy* consumed in real-time. This results in a cost impact arising from the change in quantity of *energy* over which *energy* costs are recovered in real-time versus the quantity of *energy* that were scheduled by the *day-ahead market calculation engine* for *non-dispatchable loads* and all virtual and physical *hourly* *demand response resources*[6] that are not registered as a *price responsive load*. This cost impact is accounted for by the load forecast deviation charge.

As described in MR Ch.9 s.3.2.3, the load forecast deviation charge, expressed in $/MWh, is an hourly rate that is the sum of two components:

- Real-Time Purchase Cost/Benefit; and
- DAM Volume Factor Cost/Benefit.

The load forecast deviation charge can be a positive or negative value and will be *published* on the *IESO* website.

The price paid by *non-dispatchable loads* for the real-time allocated quantity of *energy* withdrawn will be the sum of the *day-ahead market Ontario zonal price* and the hourly load forecast deviation charge. Effectively, the price adjustment to the *day-ahead market Ontario zonal price* reflects a two-*settlement* balancing, the cost of which is allocated to all *non-dispatchable loads*.

The following table provides a description of each load forecast deviation charge component.

Table 2-7: Load Forecast Deviation Charge Components

Component	Description
Real-Time Purchase Cost/Benefit	• represents the total hourly cost or benefit to all *non-dispatchable loads,* arising from *day-ahead market* load forecast deviations as assessed in the *real-time market.* • calculated as the difference between the actual *energy* consumed by *non-dispatchable loads* in real-time and the *day-ahead market* load forecast prepared by the *IESO*, multiplied by the applicable *real-time market locational marginal price.*
DAM Volume Factor Cost/Benefit	• represents the total hourly cost or benefit to all *non-dispatchable loads,* arising from *day-ahead market* load forecast deviations as assessed in the *day-ahead market.* • calculated as the difference between the *day-ahead market* load forecast prepared by the *IESO* and the actual *energy* consumed by *non-dispatchable loads*, multiplied by the *day-ahead market Ontario zonal price.*

[6] The inclusion of *hourly demand response resources* in the calculation of the load forecast deviation charge accounts for the HDR *metered quantity* as *non-dispatchable load* in real-time, and ensures that the load forecast deviation charge is not over- or under- estimated.

2.3 Day-Ahead Market Make-Whole Payment (DAM_MWP)

(MR Ch.9 s.3.4)

The purpose of the *day-ahead market* make-whole payment *settlement amount* (DAM_MWP) is to provide compensation to *dispatchable generation resources*, *dispatchable loads*, *price responsive loads*, and *boundary entity resources* that receive a *day-ahead schedule* for *energy* or *operating reserve* that deviates from their economic operating point.

When this occurs, the *market participant* might incur a lost cost where the economic operating point is less than the *market participant's day-ahead schedule*. DAM_MWP will allow the *market participant* to recover unrealized losses greater than its economic operating point.

As described in MR Ch.9 s.3.4, the DAM_MWP will be determined based on the difference in operating profit between the *resource's* economic operating point and *day-ahead schedule*, and will ensure that the *market participant* is compensated for those losses.

A *dispatchable load, price responsive load, dispatchable electricity storage resource* or *boundary entity resource* – exports, may have their *bid* price adjusted in accordance with MR Ch.9 s.3.4.3.2. The relevant price used in this adjustment process is -$125/MWh for exporters and -$15/MWh for the other types of *resources.*

All costs associated with DAM_MWP will be recovered through the *day-ahead market* uplift (DAM_UPL).

DAM_MWP will incorporate any required adjustment and mitigation test results into the calculation as described in section 4.

The *IESO* will determine a *settlement amount* under the following *charge types.*

Table 2-8: Day-Ahead Market Make-Whole Payment Settlement Amounts

Component	Charge Type Number	Charge Type Name
Component 1 – Energy	1800	Day-Ahead Market Make-Whole Payment – Energy
Component 2 – Operating Reserve	1801	Day-Ahead Market Make-Whole Payment – 10-Minute Spinning Reserve
	1802	Day-Ahead Market Make-Whole Payment – 10-Minute Non-Spinning Reserve
	1803	Day-Ahead Market Make-Whole Payment – 30-Minute Operating Reserve

As described in MR Ch.9 s.3.4, the calculation of each component, for a given *settlement hour*, may result in either a charge or credit *settlement amount*. However, DAM_MWP will only be paid when the sum of all components, as may be applicable, for the *settlement hour* is positive (greater than zero).

2.3.1 Hydroelectric Generation Resource

(MR Ch.9 s.3.4.13)

This section provides further context in regards to the DAM_MWP *settlement* for hydroelectric *generation resources* as described in MR Ch.9 s.3.4.13*.*

Market participants with hydroelectric *generation resources* may have the option to participate in the *physical market* as either a single hydroelectric *generation resource* or as part of a *cascade group* and will indicate so on a daily basis through their submitted daily *dispatch data*. Further, *market participants* can indicate if the hydroelectric *generation resource* is start-limited or not with the submission of the *maximum number of starts per day* daily *dispatch data* parameter.

If the hydroelectric *generation resource*:

- is start-limited,
- has attained max starts, and
- has a *settlement hour* that is part of a start event,

then the DAM_MWP will be calculated on a *per-start* basis for each hydroelectric *generation resource,* in accordance with MR Ch.9 s.3.4.13.4. Otherwise, the DAM_MWP will be calculated on an hourly basis in accordance with MR Ch.9 s.3.4.13.3. *Settlement hours* with a *reliability* constraint will be calculated using the hourly equation. Appendix B provides an illustration of how the *IESO* determines a start and start event.

2.3.1.1 Determining a Start and Start Event

2.3.1.1.1 Determining a Start

A start is triggered between *dispatch hour* (h) and (h+1) if the hydroelectric *generation resource's day-ahead schedule* increases above any *start indication value*, as registered by the *market participant*.

The number of starts will increase by one each time the *day-ahead schedule* increases above a registered *start indication value*. A hydroelectric *generation resource* can have multiple starts within a *dispatch hour.*

Where the number of starts in a *trading day* equals the *maximum number of starts per day*, as submitted by the daily *dispatch data,* the hydroelectric *generation resource* is considered to have attained max starts.

2.3.1.1.2 Determining a Start Event

For purposes of the DAM_MWP, a start event is defined as consisting of a set of *settlement hours* beginning with the first *settlement hour* of a start and ending with the first instance of either of the following:

- the *settlement hour* in which the *resource's day-ahead schedule* is less than the *resource's* lowest registered start indication value; or
- the *settlement hour* in which another start is triggered.

2.3.1.2 Cascade Group

This section provides further context in regards to the DAM_MWP *settlement* for hydroelectric *generation resources* that form part of a *cascade group* as described in MR Ch.9 s.3.4.13*.*

Hydroelectric *generation resources* participating as a *cascade group* may have their associated *forebays* linked for the purposes of receiving a *day-ahead schedule.* The *energy* that is scheduled for an upstream hydroelectric *generation resource* will also be scheduled on the downstream hydroelectric *generation resource*, subject to the *time lag* and *MWh ratio* submitted as *dispatch data.*

The DAM_MWP is determined based on the *day-ahead schedules* of a particular *trading day*. Hydroelectric *generation resources* in a *cascade group*, due to their *time lag*, may be scheduled into the next *trading day.* However, each *trading day* is assessed independently.

Hydroelectric *generation resources* in the *cascade group* that are not associated with *linked forebays* will be *settled* either on an hourly basis in accordance with MR Ch.9 s.3.4.13.3 or on a per-start basis in accordance with MR Ch.9 s.3.4.13.4.

Where the hydroelectric *generation resources* in a *cascade group* are associated with *linked forebays*, the DAM_MWP will first need to be assessed across all the hydroelectric *generation resources*. This assessment is necessary to offset profits and losses across all hydroelectric *generation resources* in the *cascade group* with *linked forebays*.

The *IESO* performs the following steps for a *cascade group* with *linked forebays*:

1. Assess DAM_MWP across all hydroelectric *generation resources* in the *cascade group* associated with *linked forebays* on an hourly basis in accordance with MR Ch.9 s.3.4.13.5.3 to determine the net DAM_MWP. This assessment is done irrespective if any of the hydroelectric *generation resources* have attained max starts or not.
2. After the net DAM_MWP has been determined, *settle* each hydroelectric *generation resource* on a per-*resource* basis as follows:
   a. where the net DAM_MWP assessment is greater than 0, and the hydroelectric *generation resources* have attained max starts, use the *per-start* equation in

accordance with MR Ch.9 s.3.4.13.4. Otherwise, the hourly equation is used if the hydroelectric *generation resources* are subject to the provisions of MR Ch.9 s.3.4.13.5.2;

b. where the net DAM_MWP assessment is less than or equal to 0, and the hydroelectric *generation resources* have attained max starts, use the *per-start* equation in accordance with MR Ch.9 s.3.4.13.4. Otherwise, the hydroelectric *generation resources* are ineligible for DAM_MWP.

2.4 Day-Ahead Market Generator Offer Guarantee (DAM_GOG)

(MR Ch.9 s.4.4)

The purpose of the *day-ahead market generator offer* guarantee *settlement amount* (DAM_GOG) is to provide compensation to *market participants* with *GOG-eligible resources* that have a *day-ahead operational commitment* and are unable to recover their as-*offered* costs based on the revenue earned during the *day-ahead commitment period* for *energy* and *operating reserve*. As described in MR Ch.9 s.4.4, as-*offered* costs are based on the *GOG-eligible resources*: *start-up offer*, *speed no-load offer* and incremental *energy* and *operating reserve offers.*

As described in MR Ch.9 s.4.4, the DAM_GOG *settlement amount* will be assessed for each *day-ahead commitment period* and where a *GOG-eligible resource* has multiple *day-ahead commitment periods* within a *day-ahead market dispatch day*, each *day-ahead commitment period* will be assessed separately. When a *GOG-eligible resource* is scheduled over midnight, DAM_GOG will be assessed separately for each *trading day*.

DAM_GOG will incorporate any required adjustment and mitigation test results into the calculation as described in section 4.

The *IESO* will determine a *settlement amount* for each of the five components under the following *charge types.*

Table 2-9: Day-Ahead Market Generator Offer Guarantee Settlement Amounts

Charge Type Number	Charge Type Name	Component
1804	Day-Ahead Market Generator Offer Guarantee – Energy	Component 1
1805	Day-Ahead Market Generator Offer Guarantee – Operating Reserve	Component 2
1806	Day-Ahead Market Generator Offer Guarantee – Over Midnight	Component 3
1807	Day-Ahead Market Generator Offer Guarantee – Start-up	Component 4

Charge Type Number	Charge Type Name	Component
1808	Day-Ahead Market Generator Offer Guarantee – DAM Make-Whole Payment Offset	Component 5

2.4.1 De-Synchronization of a GOG-Eligible Resource

For *reliability* reasons, the *IESO* may de-synchronize a *GOG-eligible resource* after it receives a *day-ahead operational commitment*.

As described in MR Ch.9 s.4.4, the timing of the de-synchronized event and its impact to the DAM_GOG assessment is set out in the following table.

Table 2-10: DAM_GOG Assessment for De-Synchronization of a GOG-Eligible Resource

GOG-Eligible Resource was De-synchronized	DAM_GOG Interaction with Other Settlement Amounts
After the start of its *day-ahead operational commitment*	DAM_GOG assessment will include: • *start-up offer*, and • *speed no-load offer* incurred for the *settlement hours* that the *GOG-eligible resource* was online.
Prior to the start of its *day-ahead operational commitment*	No assessment of DAM_GOG for *start-up offer* and *speed no-load offer.* *Market participants* may be able to submit claims for reimbursement of financial loss that is associated with the de-synchronized *GOG-eligible resource*. (Refer to section 2.25)

The *GOG-eligible resource* may be eligible to receive a *DAM* balancing credit *settlement amount* for those *settlement hours* where it is de-synchronized for *reliability.*

2.5 Day-Ahead Market Uplift (DAM_UPL)

(MR Ch.9 s.4.14.3)

As described in MR Ch.9 s.4.14.3, the *day-ahead market* uplift *settlement amount* (DAM_UPL) will recover the cost of the DAM_MWP and DAM_GOG*.* The calculation of the DAM_UPL will exclude the portion of the DAM_MWP and DAM_GOG that are *settled* under the *day-ahead market reliability* scheduling uplift (DRSU).

The *IESO* will allocate the *day-ahead market* uplift *settlement amount* on a daily basis to all *real-time market load resources* and exports based on their proportionate share of *energy* withdrawn (AQEW and SQEW).

The *IESO* will determine a *settlement amount* under the following *charge type.*

Table 2-11: Day-Ahead Market Uplift Settlement Amount

Charge Type Number	Charge Type Name
1850	Day-Ahead Market Uplift

2.6 Day-Ahead Market Reliability Scheduling Uplift (DRSU)

(MR Ch.9 s.4.14.4)

This section provides context for the role of the *day-ahead market reliability* scheduling uplift (DRSU) *settlement amount.* During Pass 2[7]: Reliability Scheduling and Commitment of the *day-ahead market calculation engine*, the following additional *resources* may be committed:

- *GOG-eligible resources*; or
- newly scheduled or incrementally scheduled import transactions for *boundary entity resources.*

When this occurs, the *IESO* will need to recover any additional cost associated with scheduling these *resources*. These additional costs will be recovered through the *day-ahead market reliability* scheduling uplift *settlement amount.*

As described in MR Ch.9 s.4.14.4, the DRSU will be distributed on a daily basis and will be allocated:

- first to *virtual zonal resources* with *day-ahead market schedules* to inject *energy.* The allocation will be based on their proportion of the total *energy* scheduled for all *virtual zonal resources* with *day-ahead market schedules* to inject *energy* and the quantity of *energy* that was over forecast in Pass 2 for *non-dispatchable loads* to meet actual real-time *energy demand*; and
- the remainder of the DRSU will be allocated to all *real-time market load resources* and exports based on their proportionate share of *energy* withdrawn (AQEW and SQEW).

[7] Pass 2: Reliability Scheduling and Commitment, checks if the *resources* committed by Pass 1: Market Commitment and Market Power Mitigation Pass, are sufficient to satisfy the peak forecast *demand*. Pass 2 then commits additional *resources* if required. Refer to [MR Appendix 7.5: Day-Ahead Market Calculation Engine] for further information on all the passes of the day-ahead market calculation engine.

The *IESO* will determine a *settlement amount* under the following *charge type.*

Table 2-12: Day-Ahead Market Reliability Scheduling Uplift Settlement Amount

Charge Type Number	Charge Type Name
1851	Day-Ahead Market Reliability Scheduling Uplift

2.7 Real-Time Make-Whole Payment (RT_MWP)

(MR Ch.9 s.3.5)

The purpose of the real-time make-whole payment *settlement amount* (RT_MWP) is to provide compensation to *dispatchable generation resources*, *dispatchable loads*, and *boundary entity resources* that receive a *real-time schedule* for *energy* or *operating reserve* that deviates from their economic operating point when following *IESO dispatch instructions*:

- for manual constraints; or
- when there are differences between the scheduling and pricing pass.

When this occurs, the *market participant* might incur a lost cost or lost opportunity cost, where:

- lost cost: the economic operating point is less than the *market participant's real-time schedule*. The RT_MWP will allow the *market participant* to recover unrealized losses above its economic operating point. The lost cost will not include quantities of *energy* that are included in the *day-ahead schedule*.
- lost opportunity cost: the economic operating point is greater than the *market participant's real-time schedule*. The RT_MWP will allow the *market participant* to recover unrealized profits below its economic operating point.

The RT_MWP will ensure that the *market participant* is compensated for such lost cost and lost opportunity cost losses when following such *IESO dispatch instructions*.

As described in MR Ch.9 s.3.5, for *boundary entity resources* with an export transaction, eligibility for RT_MWP will be determined according to the reason code assigned by the *IESO*. For more details on the applicable reason codes, refer to MM 4.3: Real-Time Scheduling of the Physical Markets.

A *dispatchable load, price responsive load, dispatchable electricity storage resource* or *boundary entity resource* – exports, may have their *bid* price adjusted in accordance with MR Ch.9 s.3.4.3.2. The relevant price used in this adjustment process is -$125/MWh for exporters and -$15/MWh for the other types of *resources.*

A *dispatchable load* or *dispatchable electricity storage resource* will be ineligible for *energy* lost opportunity cost (ELOC) when either ramping up or down in accordance with MR Ch.9 s.3.5.4.7, or when activated for *operating reserve* in accordance with MR Ch.9. s.3.5.4.7.1. The following table provides the conditions that must exist for the *resources* to be eligible for ELOC.

Table 2-13: Dispatchable Load and Dispatchable Electricity Storage Resource Eligibility for ELOC

Circumstance	Conditions
Ramping (MR Ch.9. s.3.5.4.7)	The following conditions exist when the *resource* is ramping up: • the *real-time schedule* increases between *metering interval* 12 of the previous *settlement hour* and *metering interval* 3 of the current *settlement hour*; and • the RT_LOC_EOP in *metering interval* 12 of the previous *settlement hour* is less than the RT_LOC_EOP in *metering interval* 1 of the current *settlement hour*; and • there is a change in the *bid* lamination, or removal of the *bid*, between the previous *settlement hour* and the next *settlement hour*. The following conditions exist when the *resource* is ramping down: • the *real-time schedule* decreases between *metering interval* 9 and 12 of the current *settlement hour*; and • the RT_LOC_EOP in *metering interval* 12 of the current *settlement hour* is greater than the RT_LOC_EOP in *metering interval* 1 of the next *settlement hour*; and • there is a change in the *bid* lamination, or removal of the *bid*, between the current *settlement hour* and the next *settlement hour*.
Activation for *operating reserve* (MR Ch.9 s.3.5.4.7.1)	The *resource* is considered to be *dispatched* in a *metering interval* as part of an activation of *operating reserve* if any of the following conditions exist: • the *real-time schedule* has a reason code 'ORA'; or • the *metering interval* is within 1 to 3 *metering intervals* in advance of the *metering interval* with the 'ORA' code; or • the *metering interval* is within 1 to 3 intervals after the *metering interval* with the 'ORA' code.

RT_MWP will incorporate any required adjustment and mitigation test results into the calculation as described in section 4.

The *IESO* will determine *settlement amounts* under the following *charge types.*

Table 2-14: Real-Time Make-Whole Payment Settlement Amounts

Charge Type Number	Charge Type Name
1900	Real-Time Make-Whole Payment – Lost Cost for Energy
1901	Real-Time Make-Whole Payment – Lost Cost for 10-Minute Spinning Reserve
1902	Real-Time Make-Whole Payment – Lost Cost for 10-Minute Non-Spinning Reserve
1903	Real-Time Make-Whole Payment – Lost Cost for 30-Minute Operating Reserve
1904	Real-Time Make-Whole Payment – Lost Opportunity Cost for Energy
1905	Real-Time Make-Whole Payment – Lost Opportunity Cost for 10-Minute Spinning Reserve
1906	Real-Time Make-Whole Payment – Lost Opportunity Cost for 10-Minute Non-Spinning Reserve
1907	Real-Time Make-Whole Payment – Lost Opportunity Cost for 30-Minute Operating Reserve

2.8 Real-Time Make-Whole Payment Uplift (RT_MWPU)

(MR Ch.9 s.3.10)

The real-time make-whole payment uplift *settlement amount* (RT_MWPU) will be allocated as part of the *hourly uplift*.

The *IESO* will determine a *settlement amount* under the following *charge type.*

Table 2-15: Real-Time Make-Whole Payment Uplift Settlement Amount

Charge Type Number	Charge Type Name
1950	Real-Time Make-Whole Payment Uplift

2.9 Day-Ahead Market Balancing Credit (DAM_BC)

(MR Ch.9 s.3.3)

The purpose of the *day-ahead market* balancing credit *settlement amount* (DAM_BC) for *market participants* with eligible *GOG-eligible resources* and *boundary entity resources* is to compensate for financial losses incurred by the *market participant* in the circumstances specified by the *market rules.*

As described in MR Ch.9 s.3.3, for each applicable *settlement hour,* the DAM_BC will be the sum of the *energy* component (BCE) and the *operating reserve* component (BCOR) for each eligible *metering interval* within such *settlement hour*, and will be calculated in accordance with MR Ch.9 ss.3.3.3-3.3.4.

The *IESO* will determine a *settlement amount* under the following *charge type.*

Table 2-16: Day-Ahead Market Balancing Credit Settlement Amount

Charge Type Number	Charge Type Name
1815	Day-Ahead Market Balancing Credit

2.10 Day-Ahead Market Balancing Credit Uplift (DAM_BCU)

(MR Ch.9 s.3.10)

The *day-ahead market* balancing credit uplift *settlement amount* (DAM_BCU) will be allocated as part of the *hourly uplift.*

The *IESO* will determine a *settlement amount* under the following *charge type.*

Table 2-17: Day-Ahead Market Balancing Credit Uplift Settlement Amount

Charge Type Number	Charge Type Name
1865	Day-Ahead Market Balancing Credit Uplift

2.11 Real-Time Generator Offer Guarantee (RT_GOG)

(MR Ch.9 s.3.6)

The purpose of the real-time *generator offer* guarantee *settlement amount* (RT_GOG) is to provide compensation to *market participants* with *GOG-eligible resources* that are committed during the *pre-dispatch scheduling process* and are unable to recover their as-*offered* costs based on the revenue earned during the *real-time commitment period* or *real-time reliability commitment period*. As described in MR Ch.9 s.3.6, subject to mitigation, as-*offered* costs are based on the *GOG-eligible resources*: *start-up offer*, *speed no-load offer* and incremental *energy* and *operating reserve offer.*

As described in MR Ch.9 s.3.6, the RT_GOG will be calculated over the *real-time commitment period* or *real-time reliability commitment period*. If a *GOG-eligible resource:*

- has multiple starts[8] within a *real-time dispatch day*, each start will be assessed separately as its own *real-time commitment period* or *real-time reliability commitment period*; or
- is scheduled over midnight, RT_GOG will be assessed separately for each *trading day*.

RT_GOG will incorporate any required adjustment and mitigation test results into the calculation as described in section 4.

The *IESO* will determine a *settlement amount* for each of the five components under the following *charge types.*

Table 2-18: Real-Time Generator Offer Guarantee Settlement Amounts

Charge Type Number	Charge Type Name	Component
1910	Real-Time Generator Offer Guarantee – Energy	Component 1
1911	Real-Time Generator Offer Guarantee – Operating Reserve	Component 2
1912	Real-Time Generator Offer Guarantee – Over Midnight	Component 3
1913	Real-Time Generator Offer Guarantee – Start-up	Component 4
1914	Real-Time Generator Offer Guarantee – RT Make-Whole Payment Offset	Component 5

2.11.1 De-Synchronization of a GOG-Eligible Resource

For *reliability* reasons, the *IESO* may de-synchronize a *GOG-eligible resource* after it receives a *real-time operational commitment*.

[8] See MM 4.3: Real-Time Scheduling of the Physical Markets.

The timing of the de-synchronized event and its impact to the RT_GOG assessment is set out in the following table.

Table 2-19: RT_GOG Assessment for De-Synchronization of GOG-Eligible Resource

GOG-Eligible Resource was De-Synchronized	RT_GOG Interaction with Other Settlement Amounts
After the start of its *pre-dispatch operational commitment*	For the *settlement hours* that the *GOG-eligible resource* was online, RT_GOG assessment will include: 1. *start-up offer,* and 2. *speed no-load offer*.
Prior to the start of its *pre-dispatch operational commitment*	No assessment of RT_GOG for *start-up offer* and *speed no-load offer.* *Market participants* may be able to submit claims for reimbursement of financial loss that is associated with the de-synchronized *GOG-eligible resource*. (Refer to section 2.25)

2.12 Real-Time Generator Offer Guarantee Uplift (RT_GOGU)

(MR Ch.9 s.4.14.2)

As described in MR Ch.9 s.4.14.2, the real-time *generator offer* guarantee uplift *settlement amount* (RT_GOGU) will be allocated on a daily basis to all *real-time market* loads and exports based on their proportionate share of *energy* withdrawn (AQEW and SQEW).

The *IESO* will determine a *settlement amount* under the following *charge type.*

Table 2-20: Real-Time Generator Offer Guarantee Uplift Settlement Amount

Charge Type Number	Charge Type Name
1960	Real-Time Generator Offer Guarantee Uplift

2.13 Generator Failure Charge (GFC)

(MR Ch.9 s.4.10)

A *GOG-eligible resource* that experiences a *generator failure*, will incur a *generator failure* charge (GFC). The specific circumstances which may give rise to a *generator failure* are further described in Table 2-23.

As described in MR Ch.9 s.4.10, there are two components to the GFC as described in the following table.

Table 2-21: Generator Failure Charge Components

Component	Description
Market Price Component	• Represents the impact of the increase to the *market price* for *energy* due to the *GOG-eligible resource's generator failure*. • Will be calculated for each *metering interval* for the failure event and will be *settled* on an hourly basis.
Guarantee Cost Component	• Represents an approximate cost of the impact to the market due to the *GOG-eligible resource's generator failure*. • Will be assessed and calculated for the failure event on a daily basis. Where a *GOG-eligible resource* has a *generator failure* event that extends into the next *trading day*, the *generator failure* event will be considered as two separate events and the *generator failure* charge will be assessed separately for each *trading day.*

The *IESO* will determine *settlement amounts* under the following *charge types.*

Table 2-22: Generator Failure Charge Settlement Amounts

Charge Type Number	Charge Type Name
1920	Generator Failure Charge – Market Price Component
1921	Generator Failure Charge – Guarantee Cost Component

2.13.1 Period Subject to the Generator Failure Charge

(MR Ch.9 s.4.10.4)

When a *generator failure* occurs, the failure intervals within the failure event, as defined in Table 2-23 must be determined.

Table 2-23: Failure Event and Failure Intervals Subject to the Generator Failure Charge

Failure Event Number	Failure Event	Failure Intervals
1	Failing to inject into the *IESO-controlled grid* to meet a *pre-dispatch operational commitment*	All *metering intervals* of the *GOG-eligible resource's binding pre-dispatch advisory schedule* issued at the time of *start-up notice*.
2	Failing to reach *minimum loading point* by the first hour of the *pre-dispatch operational commitment*	From the first *metering interval* where a *GOG-eligible resource* has a *pre-dispatch operational commitment*, until the last *metering interval* where the *GOG-eligible resource* has a *real-time schedule* less than its *minimum loading point*.
3	Failing to complete its *minimum generation block run-time*	From the first *metering interval* where the *GOG-eligible resource* has a *real-time schedule* less than its *minimum loading point*, until the last *metering interval* where the *GOG-eligible resource* has a *binding pre-dispatch advisory schedule* issued at the time of *start-up notice*.
4	Failing to complete its *extended pre-dispatch operational commitment*, where the extension period is still within the *binding pre-dispatch advisory schedule*	From the first *metering interval* where the *GOG-eligible resource* has a *real-time schedule* less than its *minimum loading point* until the earlier of: • the end of the *binding pre-dispatch advisory schedule* issued at the time of *start-up notice*; or • the end of the *binding pre-dispatch advisory schedule* at the time of extension.
5	Failing to complete its *extended pre-dispatch operational commitment*, where the extension period is outside the *binding pre-dispatch advisory schedule*	From the first *metering interval* where the *GOG-eligible resource* has a *real-time schedule* less than its *minimum loading point* until the end of its *extended pre-dispatch operational commitment*.

2.13.2 Period Subject to the Generator Failure Charge for Pseudo-Units

(MR Ch.9 s.4.10.7)

When a *generator failure* occurs for a *pseudo-unit,* the failure intervals for both the combustion turbine and steam turbine within the failure event, as defined in Table 2-24 must be determined.

Table 2-24: Failure Event and Failure Intervals Subject to the Generator Failure Charge for a Pseudo-Unit

Failure Event Number	Failure Event	Failure Intervals for the Combustion Turbine and associated Steam Turbine
1	The combustion turbine fails to inject into the *IESO-controlled grid* to meet a *pre-dispatch operational commitment*	All *metering intervals* of the combustion turbine's *pre-dispatch advisory schedule* issued at the time of *start up notice*.
2	The *pseudo-unit* operates in combined cycle mode and the combustion turbine fails to reach its *minimum loading point* by the first hour of the *pre-dispatch operational commitment*	From the first *metering interval* where the combustion turbine has a *pre-dispatch operational commitment*, until the last *metering interval* where the combustion turbine has a *real-time schedule* less than its *minimum loading point.*
3	The *pseudo-unit* operates in combined cycle mode and the combustion turbine fails to inject at an amount that is greater than or equal to its *minimum loading point* for the duration of the *pseudo-unit's minimum generation block run-time*	From the first *metering interval* where the combustion turbine has a *real-time schedule* less than its *minimum loading point,* until the last *metering interval* where the *pseudo-unit* has a *binding pre-dispatch advisory schedule* issued at the time of *start-up notice*.
4	The *pseudo-unit* operates in combined cycle mode and the combustion turbine fails to inject at an amount that is greater than or equal to *minimum loading point* for the duration of its *extended pre-dispatch operational commitment*, where the extension period is still within the *pseudo-unit's binding pre-dispatch advisory schedule* issued at the time of *start-up notice*	From the first *metering interval* where the combustion turbine has a *real-time schedule* less than its *minimum loading point*, until the earlier of: • the end of the *pseudo-unit's binding pre-dispatch advisory schedule* issued at the time of *start-up notice*; or • the end of the *pseudo-unit's binding pre-dispatch advisory schedule* at the time of extension.

Failure Event Number	Failure Event	Failure Intervals for the Combustion Turbine and associated Steam Turbine
5	The *pseudo-unit* operates in combined cycle mode and the combustion turbine fails to inject at an amount that is greater than or equal to its *minimum loading point* for the duration of its *extended pre-dispatch operational commitment*, where that extension period is outside of the *pseudo-unit's binding pre-dispatch advisory schedule* issued at the time of *start-up notice*	From the first *metering interval* where the combustion turbine has a *real-time schedule* less than its *minimum loading point*, until the end of the *pseudo-unit's extended pre-dispatch operational commitment*.
6	The *pseudo-unit* switches to *single cycle mode* after it is committed by the *pre-dispatch calculation engine* in combined cycle mode	Combustion Turbine: • from the first *metering interval* where the *energy offer* has increased or the combustion turbine has a *real-time schedule* less than its *minimum loading point,* until the last *metering interval* of the *pseudo-unit's binding pre-dispatch advisory schedule* issued at the time of *start-up notice.* Steam Turbine: • from the first *metering interval* where the steam turbine has a *real-time schedule* less than its *minimum loading point,* until the last *metering interval* of the *pseudo-unit's binding pre-dispatch advisory schedule* issued at the time of *start-up notice*.

When a steam turbine experiences a *generator failure,* the steam turbine failure intervals will be determined as the set of contiguous failure *metering intervals* starting with earliest failed *metering interval* of the *pseudo-unit* that failed and ending with the latest *metering interval* of the *pseudo-unit* that failed.

2.14 Generator Failure Charge – Market Price Component Uplift (GFC_MPCU)

(MR Ch.9 s.3.10)

The *generator failure* charge – market price component uplift *settlement amount* (GFC_MPCU) will be allocated as part of the *hourly uplift.*

The *IESO* will determine a *settlement amount* under the following *charge type.*

Table 2-25: Generator Failure Charge – Market Price Component Uplift Settlement Amount

Charge Type Number	Charge Type Name
1970	Generator Failure Charge – Market Price Component Uplift

2.15 Generator Failure Charge – Guarantee Cost Component Uplift (GFC_GCCU)

(MR Ch.9 s.4.14.1)

As described in MR Ch.9 s.4.14.1, the *generator failure* charge – guarantee cost component uplift *settlement amount* (GFC_GCCU) will be allocated on a daily basis to all *real-time market load resources* and exports based on their proportionate share of *energy* withdrawn (AQEW and SQEW).

The *IESO* will determine a *settlement amount* under the following *charge type.*

Table 2-26: Generator Failure Charge – Guarantee Cost Component Uplift Settlement Amount

Charge Type Number	Charge Type Name
1971	Generator Failure Charge – Guarantee Cost Component Uplift

2.16 Real-Time Intertie Failure Charge (RT_INFC)

(MR Ch.7 s.7.5.8B and Ch.9 s.3.7)

To provide some general context, in addition to the real-time *intertie* failure charge for *intertie* transaction failures, the *market rules* allow for compliance actions, which may include both imposing a financial penalty and/or adjusting any *settlement amounts* that were inappropriately gained or avoided by a *market participant*.

As described in MR Ch.9 s.3.7, *intertie* failure charges will apply to an *intertie* transaction for the portion of the quantity of *energy* in the *pre-dispatch schedule* that is greater than the quantity of *energy* in the *day-ahead schedule* and is not *scheduled* in the *real-time market*.

An hourly applicable price bias adjustment factor will be calculated and included in the calculation of the real-time *intertie* failure charge. The purpose of the price bias adjustment factor is to compensate for systematic differences between the pre-dispatch *intertie border price* and the *real-time market intertie border price*. Refer to Appendix C for the methodology used to calculate the price bias adjustment factor.

2.16.1 Intertie Transaction Reason Codes and Resultant Settlement Treatment

The *IESO* will apply one of several reason codes to import and export schedules to determine the appropriate *settlement* treatment. These reason codes are defined in detail in MM 4.3: Real-Time Scheduling of the Physical Markets.

The *IESO* will determine a *settlement amount* under the following *charge types.*

Table 2-27: Real-Time Intertie Failure Charge Settlement Amounts

Charge Type Number	Charge Type Name
135	Real-Time Import Failure Charge
136	Real-Time Export Failure Charge

2.17 Real-Time Intertie Failure Charge Uplift (RT_IFCU)

(MR Ch.9 s.3.10)

As described in MR Ch.9 s.3.10, the real-time *intertie* failure charge uplift *settlement amount* (RT_IFCU) will be allocated as part of the *hourly uplift*.

The *IESO* will determine a *settlement amount* under the following *charge type.*

Table 2-28: Real-Time Intertie Failure Charge Uplift Settlement Amount

Charge Type Number	Charge Type Name
186	Real-Time Intertie Failure Charge Uplift

2.18 Real-Time Intertie Offer Guarantee (RT_IOG)

(MR Ch.9 s.3.6)

Boundary entity resources are scheduled during the hour-ahead *pre-dispatch process*, which presents a price risk as they are compensated based on *real-time market locational marginal prices*, possibly resulting in the *boundary entity resource* operating at a loss. To reduce this price risk and ensure an adequate supply of *energy* into Ontario, *boundary entity resources* may be eligible to receive a single real-time *intertie offer* guarantee payment (RT_IOG), net of any IOG offsets, for an *energy* import transaction scheduled in the *real-time market*.

Day-ahead schedules are financially binding. Therefore, *energy* import transactions scheduled in the *day-ahead market* that are subsequently scheduled for the same quantity of *energy* in the *real-time market* will not be impacted by any price changes and will not be compensated for RT_IOG.

As described in MR Ch.9 s.3.6, the *settlement* of *boundary entity resources* under the *day-ahead market*, as well as other *energy* import transactions and *energy* export transactions scheduled in the *real-time market,* will need to be taken into account when determining the appropriate RT_IOG. *Energy* import transactions and *energy* export transactions for the same *market participant*, and flowing in the same *settlement hour*, are considered to be implied *linked wheeling through transactions*[9]. The *IESO* will take these *day-ahead schedules* and implied *linked wheeling through transactions* into account through the IOG offset process described below in order to determine the RT_IOG for each *settlement hour*. The *market participant* is only compensated for *real-time market energy* import transaction quantities of *energy* that do not form part of an implied *linked wheeling through transaction.*

Real-time market energy import transactions that are part of a *linked wheeling through transaction* are not eligible for a RT_IOG payment.

The *IESO* will determine a *settlement amount* under the following *charge type.*

Table 2-29: Real-Time Intertie Offer Guarantee Settlement Amount

Charge Type Number	Charge Type Name
1927	Real-Time Intertie Offer Guarantee

[9] An implied *linked wheeling through transaction* is a transaction where the import transaction and export transaction are not formally linked, in the same hour.

2.18.1 IOG Offset Process

(MR Ch.9 ss.3.6.3-3.6.5)

As described in MR Ch.9 ss.3.6.3-3.6.5, the IOG offset process involves calculating the potential RT_IOG and then subtracting the IOG_Offset amount. The IOG offset amount is determined by calculating an RT_IOG rate and multiplying it by the IOG_Offset MWs. If the total IOG_Offset MWs equals the quantity of *energy* scheduled for the eligible *real-time market energy* import transaction, the *boundary entity resource* will not receive a RT_IOG *settlement amount* for such an *energy* import transaction.

The *IESO* implements the process described below to determine the IOG_Offset MWs. Appendix D provides an illustration of the IOG offset process.

For each *market participant* and for each *settlement hour*:

Step 1: Identify all *boundary entity resource energy* transactions for the *settlement hour*, including all *real-time market* import transactions, *day-ahead market* import transactions, *real-time market* export transactions and *day-ahead market* export transactions.

Step 2: Identify and remove all *day-ahead market* and *real-time market linked wheeling through transactions*.

Step 3: Calculate the Potential_IOG for each *energy* import transaction scheduled in the *real-time market* in accordance with MR Ch.9 s.3.6.3.

- The Potential_IOG is the maximum possible RT_IOG *settlement amount* for such *real-time market energy* import transaction and is reduced by the application of the IOG offsets.

Step 4: Calculate the RT_IOG rate ($/MW) for each *energy* import transaction scheduled in the *real-time market*, in accordance with MR Ch.9 s.3.6.4.

Step 5: Remove all *energy* import transactions scheduled in the *real-time market* with a RT_IOG rate of $0/MW.

Step 6: Sort *energy* import transactions scheduled in the *real-time market* in ascending order of the RT_IOG rate.

Step 7: Determine the incremental *real-time market energy* export transactions by subtracting the quantity of *energy* for *day-ahead market* export transactions from the quantity of *energy* for *real-time market* export transactions for the same *boundary entity resource* for the same *settlement hour*.

- Any incremental *real-time market energy* export transactions will be carried forward and any incremental *day-ahead market energy* export transactions will automatically be set to 0.

After Steps 1 through 7 have been completed*,* the IOG_Offset MWs will be determined in three stages: (1) *intertie* level, (2) *neighbouring electricity system* level and (3) *IESO-control area* (Ontario) level.

Step 8: Perform the following IOG offset at the *intertie* level:

1. On the same *intertie,* identify *energy* import transactions scheduled in the *real-time market* and *energy* import transactions scheduled in the *day-ahead market,* but for which the *day-ahead energy* import transaction was not scheduled in the *real-time market.*
    a. For the *energy* import transaction scheduled in the *real-time market* with the lowest RT_IOG rate, offset the quantities of *energy* of import transactions scheduled in the *day-ahead market* but not in the *real-time market.*
    b. Repeat Step 8:1a for each *intertie*, in ascending order of RT_IOG rate*.*
    c. The remaining quantity of *energy* for any import transaction scheduled in the *day-ahead market* or in the *real-time market* that was not fully offset, or was not subject to offset at this step, will be carried forward to the next steps.
2. On the same *intertie,* identify *energy* import transactions and *energy* export transactions scheduled in the *real-time market.*
    a. For the *energy* import transaction scheduled in the *real-time market* with the lowest RT_IOG rate, offset the quantities of *energy* of export transactions scheduled in the *real-time market.*
    b. Repeat Step 8:2a for each *intertie*, in ascending order of RT_IOG rate*.*
    c. The remaining quantity of *energy* for any import transaction or export transaction scheduled in the *real-time market* that was not fully offset, or was not subject to offset at this step, will be carried forward to the next steps.

Step 9: Perform the following IOG offset at the *neighbouring electricity system* level:

1. For the same *neighbouring electricity system,* identify *energy* import transactions scheduled in the *real-time market* and *energy* import transactions scheduled in the *day-ahead market,* but for which the *day-ahead market energy* import transaction was not scheduled in the *real-time market.*
    a. For the *energy* import transaction scheduled in the *real-time market* with the lowest RT_IOG rate, offset the quantities of *energy* of import transactions scheduled in the *day-ahead market* but not in the *real- time market.*
    b. Repeat Step 9:1a for each *neighbouring electricity system*, in ascending order of RT_IOG rate*.*

c. The remaining quantity of *energy* for any import transaction scheduled in the *day-ahead market* or in the *real-time market* that was not fully offset, or was not subject to offset at this step, will be carried forward to the next steps.

2. For the same *neighbouring electricity system,* identify *energy* import transactions and *energy* export transactions scheduled in the *real-time market.*

   a. For the *energy* import transaction scheduled in the *real-time market* with the lowest RT_IOG rate, offset the quantities of *energy* of export transactions scheduled in the *real-time market.*

   b. Repeat Step 9:2a for each *neighbouring electricity system*, in ascending order of RT_IOG rate.

   c. The remaining quantity of *energy* for any import transaction or export transaction scheduled in the *real-time market* that was not fully offset, or was not subject to offset at this step, will be carried forward to the next steps.

Step 10: Perform the following IOG offset at the *IESO-control area* (Ontario) level:

1. Identify remaining *energy* import transactions scheduled in the *real-time market* and remaining *energy* import transactions scheduled in the *day-ahead market,* but for which the *day-ahead market energy* import transaction was not scheduled in the *real-time market*.

   a. For the *energy* import transaction scheduled in the *real-time market* with the lowest RT_IOG rate, offset with the quantities of *energy* of import transactions scheduled in the *day-ahead market* but not in the *real-time market.*

   b. Repeat Step 10:1a in ascending order of RT_IOG rate.

   c. The remaining quantity of *energy* for any import transaction scheduled in the *real-time market* that was not fully offset, or was not subject to offset at this step, will be carried forward to the next step.

2. Identify *energy* import transactions and *energy* export transactions scheduled in the *real-time market.*

   a. For the *energy* import transaction scheduled in the *real-time market* with the lowest RT_IOG rate, offset with the quantities of *energy* of export transactions scheduled in the *real-time market.*

   b. Repeat Step 10:2a in ascending order of RT_IOG rate.

   c. The remaining quantity of *energy* for any import transaction scheduled in the *real-time market* that was not fully offset, will be included in determining the IOG_Offset MWs.

Step 11: Determine the IOG_Offset MWs for each eligible *energy* import transaction scheduled in the *real-time market*.

Step 12: Determine the IOG_Offset ($) for each eligible *energy* import transaction scheduled in the *real-time market,* calculated in accordance with MR Ch.9 s.3.6.4.

Step 13: Determine the RT_IOG *settlement amount* for each eligible *energy* import transaction scheduled in the *real-time market,* calculated in accordance with MR Ch.9 s.3.6.3.

2.19 Real-Time Intertie Offer Guarantee Uplift (RT_IOGU)

(MR Ch.9 s.3.10)

The real-time *intertie offer* guarantee uplift *settlement amount* (RT_IOGU) will be allocated as part of the *hourly uplift.*

The *IESO* will determine a *settlement amount* under the following *charge type.*

Table 2-30: Real-Time Intertie Offer Guarantee Uplift Settlement Amount

Charge Type Number	Charge Type Name
1977	Real-Time Intertie Offer Guarantee Uplift

2.20 Internal Congestion and Loss Residuals (ICLR)

(MR Ch.9 s.4.7)

Locational pricing and the physical realities of the *IESO-controlled grid* (for e.g. congestion and line losses), mean the amount paid for *energy* by consumers does not always equal the amount paid to suppliers. This differential is known as residuals.

These residuals can arise in both the *day-ahead market* and the *real-time market* as part of the *energy settlement* from all *market participants* that consume or supply *energy.*

As described in MR Ch.9 s.4.7, the internal congestion and loss residual *settlement amount* will be calculated for each *energy market billing period* and disbursed to or collected from *load resources* at each *delivery point* during the same *energy market billing period* based on their proportionate share of *energy* withdrawn (AQEW).

The *IESO* will determine a *settlement amount* under the following *charge type.*

Table 2-31: Internal Congestion and Loss Residual Settlement Amount

Charge Type Number	Charge Type Name
1116	Internal Congestion and Loss Residual

2.21 External Congestion and Net Interchange Scheduling Limit Residuals

(MR Ch.9 s.4.8)

Residuals are created at the *interties* in the *day-ahead market* and *real-time market* as part of the *energy settlement* from all *boundary entity resources* that consume or supply *energy.*

Four types of residuals can arise at the *interties*:

- *Day-ahead market* external congestion residual;
- *Real-time market* external congestion residual;
- *Day-ahead market* net interchange scheduling limit (NISL) residual; and
- *Real-time market* net interchange scheduling limit residual.

The following table identifies the *settlement amounts* associated with each type of residual.

Table 2-32: External Congestion and NISL Residual Settlement Amounts

Residual Type	Charge Type Number and Name	Settlement
Day-Ahead Market External Congestion Residual (DAM_ECR)	*Charge type* 1117 Day-Ahead Market Net External Congestion Residual	Refer to section 2.22 for details.
Real-Time External Congestion Residual (RT_ECR)	*Charge type* 1118 Real-Time External Congestion Residual Uplift	The Real-Time External Congestion Residual Uplift (RT_ECRU) *settlement amount* will be calculated for each *energy market billing period* and disbursed to or collected from all *real-time market load resources* and exports in accordance with MR Ch.9 ss.4.8.1-4.8.4.
Day-Ahead Market Net Interchange Scheduling Limit	*Charge type* 1119 Day-Ahead Market Net Interchange	The Day-Ahead Market Net Interchange Scheduling Limit Residual Uplift (DAM_NISLRU) *settlement amount* will be allocated on a daily basis to all *real-time market load*

Residual Type	Charge Type Number and Name	Settlement
Residual (DAM_NISLR)	Scheduling Limit Residual Uplift	*resources* and exports in accordance with MR Ch.9 ss.4.8.5-4.8.7.
Real-Time Net Interchange Scheduling Limit Residual (RT_NISLR)	*Charge type* 1120 Real-Time Net Interchange Scheduling Limit Residual Uplift	The Real-Time Net Interchange Scheduling Limit Residual Uplift (RT_NISLRU) *settlement amount* will disburse the Real-Time Net Interchange Scheduling Limit Residual (RT_NISLR), calculated in accordance with MR Ch.9 s.4.8.8, on an hourly basis as part of the hourly uplift described in MR Ch.9 s.3.10.

2.22 Transmission Rights

(MR Ch.9 s.3.8.2 and s.4.9)

After payments are made to *TR holders* under *charge type* 104, the net *day-ahead market* external congestion residual (DAM_NECR), calculated in accordance with MR Ch.9 s.3.8.2, will be allocated to the *TR clearing account* for future disbursement in accordance with MR Ch.9 s.4.9*.*

The following two tables identify the *settlement amounts* applicable to *transmission rights* and under which market they are *settled*. For further information on the *TR market*, refer to MM 4.4: Transmission Rights Auction.

The following *settlement amounts* will appear on the financial market *settlement statements* and *invoices.*

Table 2-33: Transmission Rights Settlement Amounts – Financial Market

Charge Type	Settlement Amount
Charge type 52 Transmission Rights Auction Settlement Debit	*Settlement amounts* relating to transactions in all rounds of any *TR auction.*

The following *settlement amounts* will appear on the *physical market settlement statements* and *invoices.*

Table 2-34: Transmission Rights Settlement Amounts – Physical Market

Charge Type	Settlement Amount
Charge type 102 TR Clearing Account Credit	Disbursement of surplus funds from the *TR clearing account* by the *IESO* to *real-time market load resources* and exports based on their proportionate share of *energy* withdrawn (AQEW and SQEW).
Charge type 104 Transmission Rights Settlement Credit	Payment from the *IESO* to *TR holders.*
Charge type 1117 Day-Ahead Market Net External Congestion Residual	*Day-ahead market external congestion rent* collected by the *IESO*, net of payments to *TR holders* under *charge type* 104.
Charge type 168 TR Market Shortfall Debit	Payment from *market participants* to the *IESO* when payments to *TR holders* exceeds *day-ahead market external congestion rent* collected and there are insufficient funds in the *TR clearing account* to fund these payments to *TR holders.*

2.22.1 Transmission Rights Clearing Account Disbursement

(MR Ch.9 s.4.9, MR Ch.8 s.3.18.2-3.18.3)

The *IESO* will review the *TR clearing account* balance on a semi-annual basis and disburse the surplus funds in excess of the Reserve Threshold of $5M, or as directed by the *IESO Board*.

To further explain MR Ch.9 s.4.9, the surplus funds are divided into two classes, respectively, based on the proportion of total provincial *transmission service charges* (*charge type* 650, 651 and 652) and total export *transmission service charges* (*charge type* 653) collected from transmission customers during the six (6) month period immediately preceding the month-end on which it will be disbursed, or as otherwise directed by the *IESO Board* (“TRCA balance period”).

Each class of funds will then be settled as a single payout based on the total allocated quantity of *energy* withdrawn over a six (6) month prior period, or as otherwise directed by the *IESO Board* (“TRCA look-back period”)

The following representative diagram illustrates an example of a “TRCA balance period” and a “TRCA look-back period”.

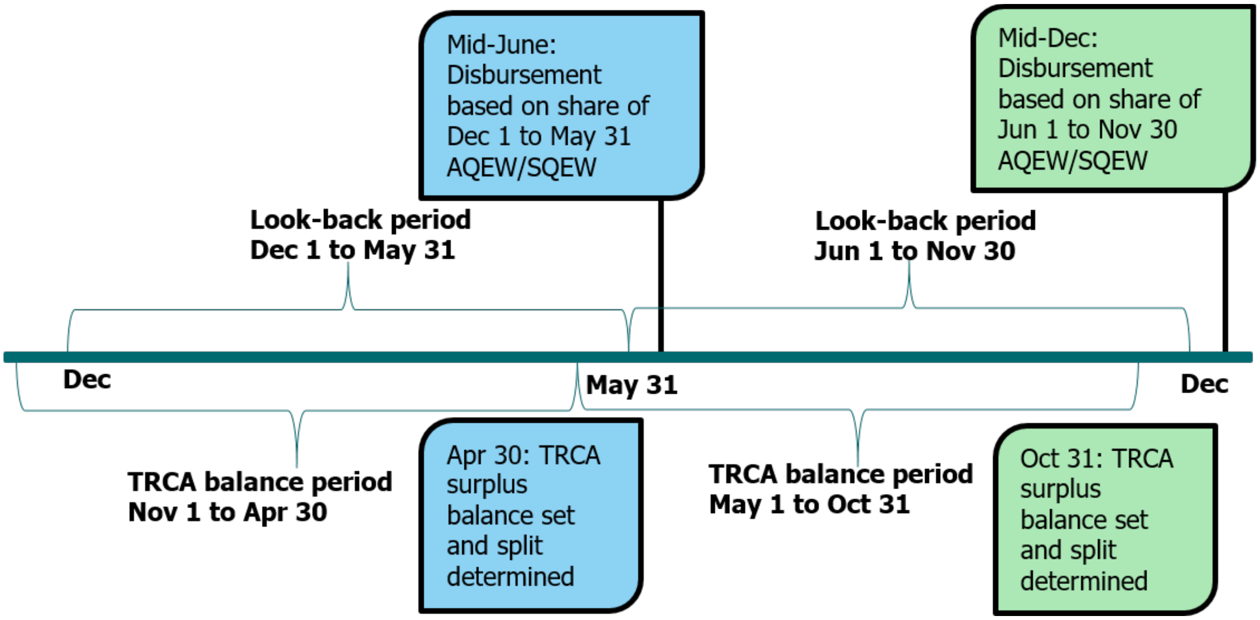

Figure 2-1: Example of TRCA balance period and TRCA look-back period

The surplus funds allocated to *load resources* are distributed based on their proportionate share of *energy* withdrawn at all *delivery points*. The surplus funds allocated to exporters are distributed based on their proportionate share of *energy* withdrawn at all *intertie metering points*.

The following diagram illustrates the disbursement of the TRCA surplus balance.

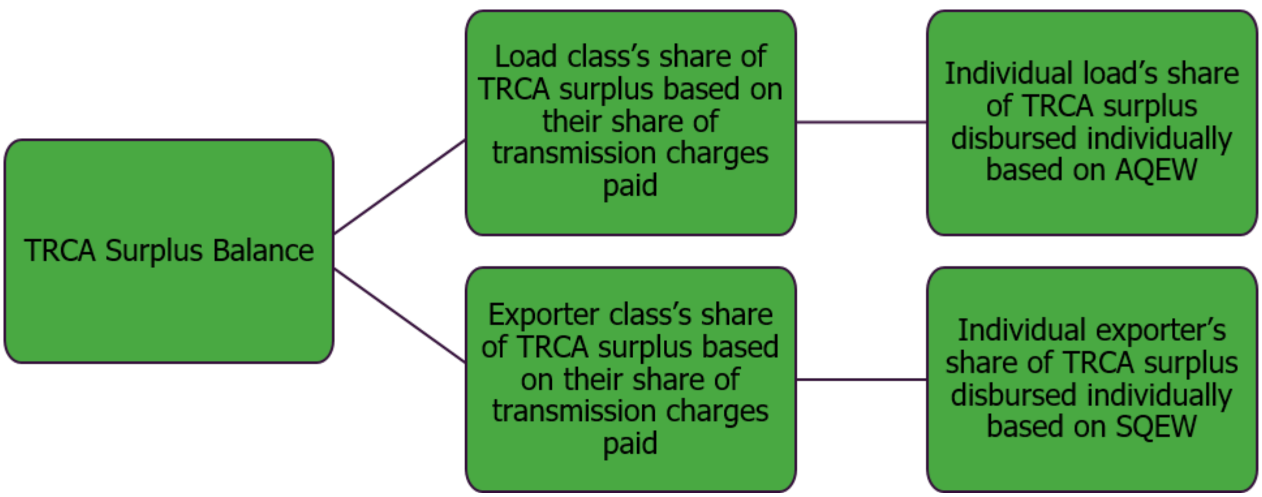

Figure 2-2: TRCA Surplus Balance Disbursement

The *IESO* will determine a *settlement amount* under the following *charge type.*

Table 2-35: Transmission Rights Clearing Account Disbursement Settlement Amount

Charge Type Number	Charge Type Name
102	TR Clearing Account Credit

2.23 Real-Time Ramp-Down Settlement Amount (RT_RDSA)

(MR Ch.9 s.4.6)

The purpose of the real-time ramp-down *settlement amount* (RT_RDSA) is to compensate *GOG-eligible resources* for ramp-down costs and, as described in MR Ch.9 s.4.6, will be calculated for *settlement hours* where the *GOG-eligible resource's real-time schedule* is less than its *minimum loading point,* indicating the *GOG-eligible resource's* intent to de-synchronize from the *IESO-controlled grid.*

The *IESO* will determine a *settlement amount* under the following *charge type*.

Table 2-36: Real-Time Ramp-Down Settlement Amount

Charge Type Number	Charge Type Name
1917	Real-Time Ramp-Down Settlement Amount

As described in MR Ch.9 s.4.6, the calculation of RT_RDSA will:

- include an adjusted *energy offer* price as described below;
- use the ramp-down factor as described below;
- be limited to the ramp-down *metering intervals* for the *trading day* in which the *GOG-eligible resource* has a *real-time schedule* less than its *minimum loading point*;
- be adjusted where the *GOG-eligible resource* has a *real-time schedule* less than its *minimum loading point* and has a *day-ahead schedule*; and
- incorporate any required adjustment and mitigation test results into the calculation as described in section 4.

2.23.1 Determining the Energy Offer for the Real-Time Ramp-Down Settlement Amount Calculation

The *energy offer* in the RT_RDSA calculation will be determined by assessing each *metering interval* that the *GOG-eligible resource* is ramping down, starting from the *metering interval* with a zero MWh *dispatch instruction* until all of the following criteria no longer exist:

- ramp-down rate limited (RDRL);
- *dispatch instruction* is less than the registered *minimum loading point*; or
- revised *dispatch instruction* is sent due to *dispatch* deviation.

The *energy offer* that will be used in the RT_RDSA calculation will be the *energy offer* from the *settlement hour* immediately preceding the last *metering interval* that was assessed and will be adjusted by a ramp-down factor of 1.3.

2.24 Real-Time Ramp-Down Settlement Amount Uplift (RT_RDSAU)

(MR Ch.9 s.4.14.11)

As described in MR Ch.9 s.4.14.11, the real-time ramp-down *settlement amount* uplift (RT_RDSAU) will be allocated on a daily basis to all *real-time market load resources* and exports based on their proportionate share of *energy* withdrawn (AQEW and SQEW).

The *IESO* will determine a *settlement amount* under the following *charge type.*

Table 2-37: Real-Time Ramp-Down Settlement Amount Uplift

Charge Type Number	Charge Type Name
1967	Real-Time Ramp-Down Settlement Amount Uplift

2.25 Fuel Cost Compensation Credit (FCC)

(MR Ch.9 s.4.11)

As described in MR Ch.9 s.4.11, the *IESO* may compensate *market participants* for the cost incurred in securing unused fuel as a result of specified *IESO* actions described in the *market rules*.

The purpose of the fuel cost compensation credit is to allow *GOG-eligible resources* to recover the cost of fuel incurred to meet the *day-ahead operational commitment* or *pre-dispatch operational commitment* that it may not otherwise be able to recover from the *IESO-administered market*. The fuel cost compensation credit is only applicable to the procurement of fuel required to achieve *minimum loading point* of the relevant operational commitment.

In order to receive a fuel cost compensation credit, a *market participant* must submit a claim to the *IESO* for such fuel costs using the “Fuel Cost Compensation” form available within Online IESO no later than one month after the *trading day* to which the claim applies to*,* with supporting documentation. In determining the direct fuel costs to be compensated, the *IESO* will use the most appropriate comparator price for the relevant fuel, as determined by the *IESO*.

If the *IESO* determines that the claim is valid, it will determine a *settlement amount* under the following *charge type.*

Table 2-38: Fuel Cost Compensation Credit Settlement Amount

Charge Type Number	Charge Type Name
1138	Fuel Cost Compensation Credit

2.26 Fuel Cost Compensation Credit Uplift (FCCU)

(MR Ch.9 s.4.14.8)

As described in MR Ch.9 s.4.14.8, the fuel cost compensation credit uplift *settlement amount* (FCCU) will be allocated on a monthly basis to all *real-time market load resources* and exports based on their proportionate share of *energy* withdrawn (AQEW and SQEW).

The *IESO* will determine a *settlement amount* under the following *charge type.*

Table 2-39: Fuel Cost Compensation Credit Uplift Settlement Amount

Charge Type Number	Charge Type Name
1188	Fuel Cost Compensation Credit Uplift

2.27 Station Service Rebate

(MR Ch.9 ss.2.2.12-2.2.16)

Some *facilities* in the *IESO-administered markets* consume *energy* as *station service*. As described in MR Ch.9 ss.2.2.12-2.2.16, *metered market participants* for certain *facilities* are eligible for a reimbursement of the *hourly uplift* and non-*hourly uplift settlement amounts* related to AQEW consumed as *station service*. The *station service* rebate is applicable to:

- *generation facilities* that consume *energy* as *generation station service*; and
- *electricity storage facilities* that consume *energy* as *electricity storage station service*.

If the *metered market participant* believes that their *facility* is eligible for a *station service* rebate, the *metered market participant* should:

- download IMO_FORM_1419 "Application for Designation of a Facility for Generation Station Service Rebate" from the *IESO* website;
- complete all applicable sections; and
- submit the form to the *IESO*.

The *IESO* will:

- review the *market participant's* application;
- request additional information in order to assess the application, if necessary;
- determine if the *generation facility* meets the requirements for the rebate designation; and
- notify the *market participant* in writing of the *IESO's* determination.

If the requirements are met for the rebate designation, the *IESO* will adjust, on the last *trading day* of the month, the *hourly uplift* and non-*hourly uplift settlement amounts* that may have accumulated at the *station service delivery point* during the periods where the eligible *facility* was a net injection of *energy* into the *IESO-controlled grid*.

The *IESO* will determine a *settlement amount* under the following *charge type.*

Table 2-40: Station Service Reimbursement Credit

Charge Type Number	Charge Type Name
119	Station Service Reimbursement Credit

2.28 Station Service Debit

(MR Ch.9 s.2.2.17)

As described in MR Ch.9 s.4.14.12, the *station service* debit *settlement amount* will be allocated on a monthly basis to all *real-time market load resources* and exports based on their proportionate share of *energy* withdrawn (AQEW and SQEW).

The *IESO* will determine a *settlement amount* under the following *charge type.*

Table 2-41: Station Service Reimbursement Debit

Charge Type Number	Charge Type Name
169	Station Service Reimbursement Debit

3 Other Market Charges, Credits and Uplifts

3.1 Forecasting Services

(MR Ch.9 s.4.12)

The *IESO* has established forecasting services as a procured service to accommodate *variable generation* from wind and solar *resources*. The forecasting service *settlement amount* will be paid to forecasting service providers.

The *IESO* will determine a *settlement amount* under the following *charge type.*

Table 3-1: Forecasting Service Settlement Amount

Charge Type Number	Charge Type Name
1600	Forecasting Service Settlement Amount

3.2 Forecasting Service Uplift

(MR Ch.9 s.4.12.1)

As described in MR Ch.9 s.4.14.12, the forecasting service balancing amount *settlement amount* will be allocated on a monthly basis to all *real-time market load resources* and exports based on their proportionate share of *energy* withdrawn (AQEW and SQEW).

The *IESO* will determine a *settlement amount* under the following *charge type.*

Table 3-2: Forecasting Service Uplift Settlement Amount

Charge Type Number	Charge Type Name
1650	Forecasting Service Balancing Amount

3.3 Adjustment Account Surplus Disbursement

(MR Ch.9 s.6.20.5.3)

As described in MR Ch.9 s.6.20.5.3, the *IESO Board* will review, at least annually, the allocation of any credit balance in the *IESO adjustment account*. The *IESO Board* may direct the usage of such funds in accordance with MR Ch.9 s.6.20.5.3, which may include some or all of the credit balance (surplus) be distributed to *market participants*. The disbursement, if applicable, will be settled as a single payout on the basis determined by the *IESO Board*. Any such disbursement will be distributed to *market participants* as a non-hourly *settlement amount.*

The *IESO* will determine a *settlement amount* under the following *charge type*.

Table 3-3: Adjustment Account Surplus Disbursement Settlement Amount

Charge Type Number	Charge Type Name
9920	Adjustment Account Credit

3.4 Capacity Obligations

(MR Ch.9 s.4.13)

[NTD: To be provided following the finalization of the Capacity Auction Market Rule Amendment]

3.5 Dispute Resolution Settlement

(MR Ch.3 s.2.7 and Ch.9 s.6.10)

After the successful resolution of a dispute between the *IESO* and a *market participant*, the *IESO* will determine a *settlement amount* under the following *charge type.*

Table 3-4: Dispute Resolution Settlement Amount

Charge Type Number	Charge Type Name
700	Dispute Resolution Settlement Amount

The *settlement amount* can be an amount due to or owed by the *market participant* and will be fully balanced by one of the following *settlement amounts*, depending on the nature of the dispute and the associated resolution.

Table 3-5: Dispute Resolution Balancing Settlement Amount

Charge Type Number	Charge Type Name	Allocation
750	Dispute Resolution Balancing Amount (IESO)	Due to or owed by the *IESO* Adjustment Account and will be allocated on a monthly basis.

Charge Type Number	Charge Type Name	Allocation
1750	Dispute Resolution Balancing Amount (Market)	Due to or owed by *market participants* and will be allocated on a monthly basis to all *real-time market load resources* and exports based on their proportionate share of *energy* withdrawn AQEW and SQEW.

– End of Section –

4 Market Power Mitigation

(MR Ch.9 s.5)

This section describes the impacts to the *settlement process* when the *IESO* implements the market power mitigation process to assess the exercise of global market power and local market power. For detailed information on the market power mitigation framework and processes, refer to MM 14.1: Market Power Mitigation Procedures and MM 14.2: Reference Level and Reference Quantity Procedures. The following *settlement* charges and *settlement amounts* are described in this section:

- Reference Level Settlement Charges
- Ex-Post Mitigation Settlement Charges
- Settlement Mitigation of Settlement Amounts

4.1 Reference Level Settlement Charges (RLSC)

(MR Ch.9 ss.5.2-5.3)

Market participants that have *generation resources* with multiple cost profiles can make a request to the *IESO* through the mitigation process to use its higher-cost profile *reference level value*. This request must be accompanied by sufficient supporting documentation as further described in MR Ch.7 s.22.5.11 and MM 14.2: Reference Level and Reference Quantity Procedures.

Where the conditions set out in MR. Ch.9 s.5.2.1.1, for the *day-ahead market*, or MR Ch.9 s.5.3.1.1, for the *real-time market*, are satisfied, a *reference level settlement* charge (RLSC) *settlement amount* will be triggered and:

- calculated in accordance with MR Ch.9 s.5.2 for the *day-ahead market* reference level *settlement* charge (DAM_RLSC); or
- calculated in accordance with MR Ch.9 s.5.3 for the real-time *reference level settlement* charge (RT_RLSC).

The *IESO* will determine a *settlement amount* under the following *charge types*.

Table 4-1: Reference Level Settlement Charge

Charge Type Number	Charge Type Name
1930	Day-Ahead Market Reference Level Settlement Charge
1931	Real-Time Reference Level Settlement Charge

4.2 Reference Level Settlement Charge Uplifts (RLSCU)

(MR Ch.9 s.5.10)

The uplift *settlement amounts* associated with the respective *reference level settlement* charges will be allocated as follows:

- *day-ahead market reference level settlement* charge uplift (DAM_RLSCU): allocated as part of the *hourly uplift*;
- real-time *reference level settlement* charge uplift (RT_RLSCU): allocated as part of the *hourly uplift*.

The *IESO* will determine a *settlement amount* under the following *charge types*.

Table 4-2: Reference Level Settlement Charge Uplifts

Charge Type Number	Charge Type Name
1980	Day-Ahead Market Reference Level Settlement Charge Uplift
1981	Real-Time Reference Level Settlement Charge Uplift

4.3 Ex-Post Mitigation Settlement Charges

(MR Ch.9 ss.5.4-5.5)

The *settlement process* will support the ex-post market power mitigation activities performed after the *IESO* issues the final *settlement statement* for any *trading day* as described in MM 14.1: Market Power Mitigation Procedures.

4.3.1 Ex-Post Mitigation for Physical Withholding Settlement Charges (EXP_PWSC)

(MR Ch.9 s.5.4)

As described in MM 14.1: Market Power Mitigation Procedures, the *IESO* will apply market power mitigation tests to determine whether any *market participants* engaged in *physical withholding.* These mitigation processes will test for *physical withholding* of *energy* and *operating reserve* in both the *day-ahead market* and *real-time market.*

As described in MR Ch.9 s.5.4, the ex-post mitigation for *physical withholding settlement* charge (EXP_PWSC) *settlement amounts* will be a charge to the *market participant* where the market power mitigation processes have determined that the *market participant* engaged in *physical withholding*.

The *IESO* will determine a *settlement amount* under the following *charge types.*

Table 4-3: Ex-Post Mitigation for Physical Withholding Settlement Charges

Charge Type Number	Charge Type Name
1932	Mitigation Amount for Physical Withholding – Energy
1933	Mitigation Amount for Physical Withholding – 10R Operating Reserve
1934	Mitigation Amount for Physical Withholding – 10N Operating Reserve
1935	Mitigation Amount for Physical Withholding – 30R Operating Reserve

4.3.2 Ex-Post Mitigation for Economic Withholding on Uncompetitive Interties Settlement Charges (EXP_EWSC)

(MR Ch.9 ss.5.5)

As described in MM 14.1, the *IESO* will apply market power mitigation tests to determine whether any *market participants* engaged in *intertie economic withholding.*

As described in MR Ch.9 ss.5.5, the ex-post mitigation for *economic withholding* on uncompetitive *interties settlement* charge (EXP_EWSC) *settlement amounts* will be a charge to the *market participant* where the market power mitigation processes have determined that the *market participant* engaged in *intertie economic withholding*.

The *IESO* will determine a *settlement amount* under the following *charge types*.

Table 4-4: Ex-Post Mitigation for Economic Withholding on Uncompetitive Interties Settlement Charges

Charge Type Number	Charge Type Name
1936	Mitigation Amount for Intertie Economic Withholding – Energy
1937	Mitigation Amount for Intertie Economic Withholding – 10N Operating Reserve
1938	Mitigation Amount for Intertie Economic Withholding – 30R Operating Reserve
1939	Mitigation Amount for Intertie Economic Withholding – Make-Whole Payment

4.3.3 Ex-Post Mitigation Settlement Charge Uplift (EXP_MSCU)

(MR Ch.9 ss.4.14.9-4.14.10)

As described in MR Ch.9 ss.4.14.9-4.14.10, the uplift *settlement amounts* associated with the respective ex-post mitigation *settlement* charges will be allocated as follows:

- mitigation amount for *physical withholding* uplift (EXP_PWSCU): allocated on a monthly basis to all *real-time market load resources* and exports based on their proportionate share of *energy* withdrawn (AQEW and SQEW), calculated in accordance with MR Ch.9 s.4.14.9.

- mitigation amount for *intertie economic withholding* uplift (EXP_EWSCU): allocated on a monthly basis to all *real-time market load resources* and exports based on their proportionate share of *energy* withdrawn (AQEW and SQEW), calculated in accordance with MR Ch.9 s.4.14.10.

The *IESO* will determine a *settlement amount* under the following *charge type*:

Table 4-5: Ex-Post Mitigation Settlement Charge Uplifts

Charge Type Number	Charge Type Name
1982	Mitigation Amount for Physical Withholding Uplift
1986	Mitigation Amount for Intertie Economic Withholding Uplift

4.4 Settlement Mitigation of Settlement Amounts

(MR Ch.9 s.5.1 and Appendix 9.4)

The *IESO* will perform conduct and impact tests to determine the appropriate *settlement amounts* to be paid to *market participants*. For details on the *reliability* codes, refer to MM 4.3: Real-Time Scheduling of the Physical Markets.

The purpose of the conduct test, as set out in MR Ch.9 s.App.9.4, is to determine whether enhanced mitigated *dispatch data* is applicable and the values of such enhanced mitigated *dispatch data*.

Where that enhanced mitigated *dispatch data* is applicable, the impact test, as set out in MR Ch.9 s.5, determines whether that data should be used in the final calculation of the following *settlement amounts*:

- *day-ahead market* make-whole payment *settlement amount*
- *day-ahead market generator offer* guarantee *settlement amount*
- real-time make-whole payment *settlement amount*
- real-time *generator offer* guarantee *settlement amount*
- real-time ramp-down *settlement amount*.

5 Market Remediation

(MR Ch.7 s.8.4A and Ch.9 s.2.14)

Potential market tool failures and errors may impact the operability of the *IESO-administered markets.* The *IESO* will assess the impact to the *IESO-administered markets* and will resolve incorrect and/or missing data and take corrective, appropriate action, that is specific to the timeframe in which the market failure and/or error occurred.

The *IESO* may take any of the following actions, depending on the specific circumstances, in either the *day-ahead market* or *real-time market*:

- administrative pricing;
- declare a *dispatch scheduling error;*
- declare a market failure; or
- declare a market suspension.

Published results may also be deemed invalid due to a number of factors, and corrective actions may be required after-the-fact. Refer to MM 4.5: Market Suspension and Resumption and MM 4.6: Market Remediation.

For additional clarity, in the event that a pre-dispatch error or a calculation engine failure occurs, no corrections to *pre-dispatch schedules* or prices will be made. Deviations from the last recorded and *published pre-dispatch calculation engine* run will be reflected in real-time inputs for *non-quick start resources* and *intertie* transactions through transaction codes.

The results of these corrective actions will be received by the *settlement process* and *settlement amounts* will be calculated using this data.

Appendix A: Forms

This appendix contains a list of forms associated with this *market manual*, which are available on the *IESO's* website (http://www.ieso.ca/). The forms included are as follows:

Table A-1: List of Forms

Form Name	Form Number
Fuel Cost Compensation	TBD
Application for Designation of a Facility for Generation Station Service Rebate	IMO_FORM_1419

– End of Section –

Appendix B: Hydroelectric Generation Resources – Determining a Start and Start Event

B.1. Determining a Start

The following figure depicts an example of the *day-ahead schedule* for a hydroelectric *generation resource* for the first six *settlement hours* of a *trading day*, including HE4 which was issued for *reliability* reasons. In this example, the hydroelectric *generation resource* has registered three *start indication values* (SIV).

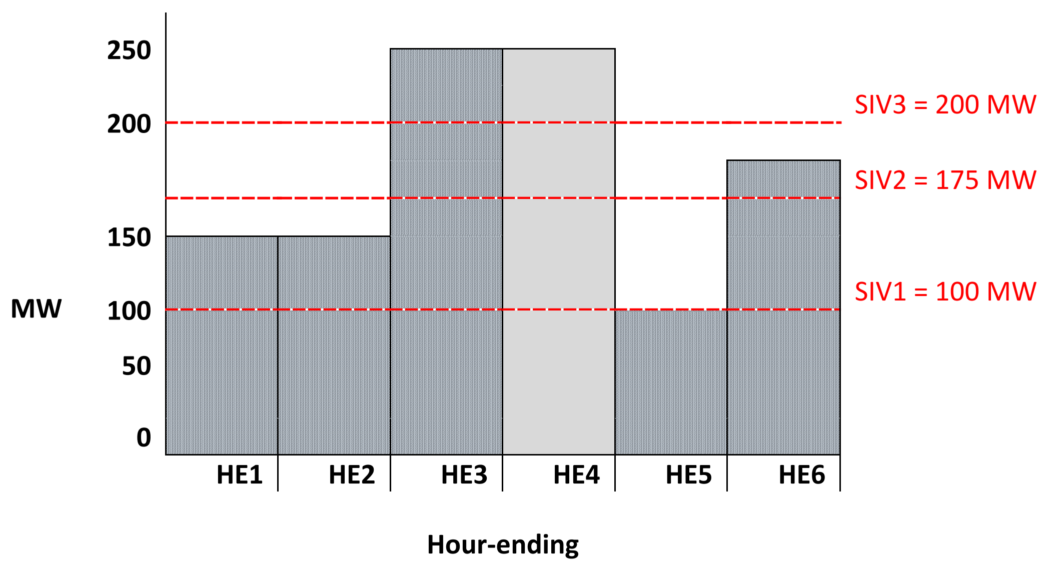

Figure B-1: Determining a Start

For the hydroelectric *generation resource*, the *maximum number of starts per day* submitted by the *market participant* is four.

The following table shows the *IESO*'s assessment of each *settlement hour* and how it would come to the conclusion that the hydroelectric *generation resource* has four starts (in HE1, HE3, HE3, and HE6). This equals the *maximum number of starts per day* submitted. Therefore, the hydroelectric *generation resource* has attained max starts.

Table B-1: IESO Assessment of Starts in Each Settlement Hour

Hour-ending	Day-Ahead Schedule	Assessment
HE1	150 MW	A start is counted in HE1 as the *day-ahead schedule* is 150 MW, which is above the first *start indication value* (SIV1).
HE2	150 MW	The *day-ahead schedule* is 150 MW and does not increase above another *start indication value*. Therefore, there is no start.
HE3	250 MW	The *day-ahead schedule* is 250 MW. In this *settlement hour*, two starts are counted as the hydroelectric *generation resource* increases above SIV2 (175 MW) and SIV3 (200 MW)
HE4	250 MW dispatched for *reliability*	The *day-ahead schedule* is 250 MW and does not increase over another *start indication value*. Therefore, no start is counted.
HE5	100 MW	The *day-ahead schedule* is 100 MW which is below SIV3 and SIV2. Therefore, no start is counted.
HE6	185 MW	The *day-ahead schedule* is 185 MW and increases from the *day-ahead schedule* in HE5 and increases above SIV2. Therefore a start is counted.

B.2. Determining a Start Event

Continuing with the above example, the following assessment will illustrate how the *IESO* determines which *settlement hours* are included in a start event.

Table B-2: IESO Determination of Settlement Hours in a Start Event

Hour-ending	Assessment
HE1	The first start is triggered and therefore is the beginning of start event 1.
HE2	Does not decrease below the lowest *start indication value* and no new start is triggered. Therefore, the *settlement hour* is also part of start event number 1.
HE3	Another start is triggered and therefore is the beginning of start event 2.

Hour-ending	Assessment
HE4	The hydroelectric *generation resource* was dispatched for *reliability*. Therefore, the hour will not be included in a start event. Start event 2 will continue to be assessed in the next *settlement hour*.
HE5	The *day-ahead schedule* does not decrease below the lowest *start indication value* and no new start is triggered. The *dispatch hour* will be included in start event 2.
HE6	Another start is triggered and is the beginning of start event 3.

Based on this assessment, the hydroelectric *generation resource* has three start events as described in the following table.

Table B-3: Start Events and DAM_MWP Calculations

Start Event	Hours	DAM_MWP Calculation
Start event 1	HE1 to HE2	DAM_MWP will be calculated on a *per-start* basis, in accordance with MR Ch.9 s.3.4.13.4.
Start event 2	HE3 to HE5, excluding HE4	DAM_MWP will be calculated on a *per-start* basis, in accordance with MR Ch.9 s.3.4.13.4, with the exception of HE4 which will be calculated on an hourly basis, in accordance with MR Ch.9 s.3.4.13.5.2.
Start event 3	HE6	DAM_MWP will be calculated on a *per-start* basis, in accordance with MR Ch.9 s.3.4.13.4.

– End of Section –

Appendix C: Price Bias Adjustment Factors Calculation Method for the Real-Time Import and Export Failure Charge

(MR Ch.9 s.3.7)

The real-time failure charge calculation for imports and exports includes the difference between the pre-dispatch and the *real-time market energy market prices* during the *settlement hour* of the failure. Including transaction failure, there are many factors that contribute to these *market price* differences. The purpose of the price bias adjustment factors is to adjust this charge to take into account some of the systemic reasons for such differences in *market prices.*

The following calculation method produces twenty-four hourly factors that apply for a three-month period. These three-month periods are aligned with the seasons.

The periods are:

- the winter factors apply to December, January, and February;
- the spring factors apply to March, April, and May;
- the summer factors apply to June, July, and August; and
- the autumn factors apply to September, October, and November.

Effective time for each three-month block starts at the first hour of the first day of the month and ends at the twenty-fourth hour of the last day of the third month in the block.

The *IESO* uses the following methodology to calculate the price bias adjustment factors.

Data Set

The total data set used to calculate the price bias adjustment factors includes all historical differences in *energy market price* between pre-dispatch and the *real-time market*, including those differences which are zero, positive, and negative. This total data set includes all differences from the start of the Ontario market (May 1, 2002) until the present calendar year.

The *IESO* calculates each hourly price bias adjustment factor using a subset of the total data set. All the price differences are divided into those which occurred in each hour of the day during each seasonal block defined above. The price bias adjustment factors are calculated using the corresponding hours in the corresponding months. For example, the spring factor for hour 1 is calculated using all the price differences from hour 1 for the months of March, April, and May of each year since market opening. This results in data sets that are hourly, seasonal, and yearly.

The *IESO* then creates frequency distributions for these data sets and determines the median values of the frequency distributions.

Weighting Factors

Each yearly median value is assigned a weighting factor from 0 to 1. A year with a weighting factor of zero results in that year's median value not contributing to the determination of the price bias adjustment factor. Conversely, a year assigned a weighting factor of 1 will solely be considered at the exclusion of all other years. After taking into account the weighing factors, the *IESO* determines a price bias adjustment for each hour of the day for a three-month block.

The use of weighing factors allows the *IESO* to establish the best forecast by enabling the price bias adjustment factors to reflect short-term and long-term influences. The weighting factor assignments are at the *IESO's* discretion.

These calculations result in twenty-four hourly price bias adjustment factors for each season of the year. These factors are the same for the import and export *settlement* charge.

The *IESO* will *publish* the price bias adjustment factors in advance of their effective *trading day*.

– End of Section –

Appendix D: IOG Offset Process

The following is an example of the IOG offset process as described in section 2.18.

For *market participant* 123456 in *settlement hour* 4, the *boundary entity resources* received the following *energy* import transactions and *energy* export transactions in the *real-time market* and the *day-ahead market*.

Table D-1: Real-Time Market Energy Intertie Transactions

	Boundary Entity Resource	MW (SQEI)	Intertie	Neighbouring Electricity System	Potential_IOG	RT_IOG Rate ($/MW)
RT Import Transactions	Res1	100	PQQC	HQ	$1,000	$10
	Res4	400	PQBE	HQ	$8,000	$20
	Res5	100	MBSI		$3,000	$30
	Res9	100	MBSI		$4,000	$0
RT Export Transactions	Res6	100	MNSI			
	Res7	100	MBSI			
	Res8	100	PQXY	HQ		

Table D-2: Day-Ahead Market Energy Intertie Transactions

	Boundary Entity Resource	MW (DAM_SQEI)	Intertie	Neighbouring Electricity System
DAM Import Transactions	Res11	50	PQQC	HQ
	Res2	100	MBSI	
	Res3	100	MNSI	
	Res9	150	MNSI	
DAM export transactions	Res6	50	MNSI	

1. The real-time *energy* import transaction associated with Res9 is removed as it has a RT_IOG rate of $0/MW. The corresponding *DAM energy* import transaction is automatically removed as the *DAM schedule* of 150MW is greater than the *real-time schedule* of 100MW.
2. Determine the incremental *real-time market energy* export transactions for any *boundary entity resource* that was scheduled for an export transaction in the *day-ahead market* and the *real-time market*.

Table D-3: Incremental Real-Time Energy Export Transactions

Energy Transaction	Res6
	MNSI
RT Export MW	100
DAM Export MW	50
Offset MW	**50**
Remaining RT Export MW - Res6	**50**

3. Perform the IOG offset at the *intertie level*.

a. On the same *intertie*, identify *energy* import transactions scheduled in the *real-time market* and *energy* import transactions scheduled in the *day-ahead market* but for which the *day-ahead market energy* import transaction was not scheduled in the *real-time market*.

Table D-4: IOG Offset at Intertie Level

Energy Transaction	PQQC
RT Import MW - Res1	100
DAM Import MW - Res11	50
Offset MW	**50**
Remaining RT Import MW - Res1	**50**

Energy Transaction	MBSI
RT Import MW - Res5	100
DAM Import MW - Res2	100
Offset MW	**100**
Remaining RT Import MW - Res5	**-**

b. On the same *intertie*, offset *energy* import transactions and *energy* export transactions scheduled in the *real-time market*.

c. There are no remaining offset of MWs at the *intertie* level. The remaining quantity of *energy* for any *intertie* transaction not offset will be carried forward to the next IOG offset level: *neighbouring electricity system* level.

4. Perform the IOG offset at the *neighbouring electricity system* level.

a. In the same *neighbouring electricity system*, identify *energy* import transactions scheduled in the *real-time market* and *energy* import transactions scheduled in the *day-ahead market* but for which the *day-ahead market energy* import transaction was not scheduled in the *real-time market*.

Table D-5: IOG Offset at Neighbouring Electricity System Level

Energy Transaction	HQ
RT Import MW - Res1	50
RT Import MW - Res4	400
DAM Import MW	-
Offset MW	**-**

Energy Transaction	HQ
Remaining RT Import MW - Res1	**50**
Remaining RT Import MW - Res4	**400**

- There is no offset of MWs at this step.

b. In the same *neighbouring electricity system*, offset *energy* import transactions and *energy* export transactions scheduled in the *real-time market*.

Table D-6: IOG Offset at Neighbouring Electricity System Level

Energy Transaction	HQ
RT Import MW - Res1	50
RT Import MW - Res4	400
RT Export MW - Res8	100
Offset MW	**100**
Remaining RT Import MW - Res1	**-**
Remaining RT Import MW - Res4	**350**

c. The remaining quantity of *energy* for any *intertie* transaction not offset will be carried forward to the next IOG offset level: *IESO-control area* (Ontario) level.

5. Perform the IOG offset at the *IESO-control area* (Ontario) level.

The following *energy* import and export transactions are available for offset.

Table D-7: IOG Offset at IESO-Control Area (Ontario) Level

Energy Transaction	Res4 PQBE	Res6 MNSI	Res3 MNSI	Res7 MBSI
RT Import MW	350	-	-	-
DAM Import MW	-	-	100	-
RT Export MW	-	50	-	100

a. Identify *energy* import transactions scheduled in the *real-time market* and *energy* import transactions scheduled in the *day-ahead market* but for which the *day-ahead market energy* import transaction was not scheduled in the *real-time market*.

Table D-8: IOG Offset at IESO-Control Area (Ontario) Level

Energy Transaction	MWs
RT Import MW - Res4	350
DAM Import MW - Res3	100
Remaining RT Import MW - Res4	**250**

b. Offset *energy* import transactions and *energy* export transactions scheduled in the *real-time market*.

Table D-9: IOG Offset at IESO-Control Area (Ontario) Level

Energy Transaction	MWs
RT Import MW - Res4	250
RT Export MW - Res6	50
RT Export MW - Res7	100
Remaining RT Import MW - Res4	**100**

c. RT import transaction – Res4 was offset:

- 50MW at the *neighbouring electricity system* level, and
- 250MW at the *IESO-control area* (Ontario) level.

Total IOG_Offset MWs is 300MW.

6. The RT_IOG *settlement amount* for Res4 is determined as follows.

Table D-10: RT_IOG Settlement Amount

Potential_IOG	$8,000
IOG_Offset MWs	300
IOG_Rate	$20

= Max [Potential_IOG - IOG_Offset, 0]
= Max [$8000 - (300 x $20),0]
= $2000

Res4 will receive a *settlement amount* under *charge type* 1927 – Real-Time Intertie Offer Guarantee.

– End of Section –

List of Acronyms

Acronym	Term
AQEW	Allocated quantity of energy withdrawn
BCE	Balancing Credit - Energy
BCOR	Balancing Credit - Operating Reserve
DAM_BC	Day-Ahead Market Balancing Credit
DAM_BCU	Day-Ahead Market Balancing Credit Uplift
DAM_ECR	Day-Ahead Market External Congestion Residual
DAM_GOG	Day-Ahead Market Generator Offer Guarantee
DAM_MWP	Day-Ahead Market Make-Whole Payment
DAM_NECR	Day-Ahead Market Net External Congestion Residual
DAM_NISLR	Day-Ahead Market Net Interchange Scheduling Limit Residual
DAM_NISRU	Day-Ahead Market Net Interchange Scheduling Limit Residual Uplift
DAM_RLSC	Day-Ahead Market Reference Level Settlement Charge
DAM_RLSCU	Day-Ahead Market Reference Level Settlement Charge Uplift
DAM_UPL	Day-Ahead Market Uplift
DRSU	Day-Ahead Market Reliability Scheduling Uplift
ELOC	Energy lost opportunity cost
EXP_EWSC	Ex-Post Mitigation for Economic Withholding on Uncompetitive Interties Settlement Charge
EXP_EWSCU	Ex-Post Mitigation for Economic Withholding on Uncompetitive Interties Settlement Charge Uplift
EXP_PWSC	Ex-Post Mitigation for Physical Withholding Settlement Charge
EXP_PWSCU	Ex-Post Mitigation for Physical Withholding Settlement Charge Uplift
FCC	Fuel Cost Compensation Credit
FCCU	Fuel Cost Compensation Credit Uplift
GFC	Generator Failure Charge
GFC_GCC	Generator Failure Charge - Guarantee Cost Component
GFC_GCCU	Generator Failure Charge - Guarantee Cost Component Uplift
GFC_MPC	Generator Failure Charge - Market Price Component
GFC_MPCU	Generator Failure Charge - Market Price Component Uplift

Acronym	Term
HDR	Hourly demand response resource
HORSA	Hourly Operating Reserve Settlement Amount
HPTSA	Hourly Physical Transaction Settlement Amount
HPTSA_NDG	Hourly Physical Transaction Settlement Amount - Non-Dispatchable Generator
HPTSA_NDL	Hourly Physical Transaction Settlement Amount - Non-Dispatchable Load
HVTSA	Hourly Virtual Transaction Settlement Amount
ICLR	Internal Congestion and Loss Residual
IOG	Intertie offer guarantee
NISL	Net interchange scheduling limit
OEB	Ontario Energy Board
PBC	Physical bilateral contract
RDRL	Ramp-down rate limited
RLSC	Reference Level Settlement Charge
RLSCU	Reference Level Settlement Charge Uplift
RT_ECR	Real-Time External Congestion Residual
RT_ECRU	Real-Time External Congestion Residual Uplift
RT_GOG	Real-Time Generator Offer Guarantee
RT_GOGU	Real-Time Generator Offer Guarantee Uplift
RT_INFC	Real-Time Intertie Failure Charge
RT_INFCU	Real-Time Intertie Failure Charge Uplift
RT_IOG	Real-Time Intertie Offer Guarantee
RT_IOGU	Real-Time Intertie Offer Guarantee Uplift
RT_LOC_EOP	Real-Time Lost Opportunity Cost Economic Operating Point
RT_MWP	Real-Time Make-Whole Payment
RT_MWPU	Real-Time Make-Whole Payment Uplift
RT_NISLR	Real-Time Net Interchange Scheduling Limit Residual
RT_NISLRU	Real-Time Net Interchange Scheduling Limit Residual Uplift
RT_RDSA	Real-Time Ramp-Down Settlement Amount
RT_RDSAU	Real-Time Ramp-Down Settlement Amount Uplift
RT_RLSC	Real-Time Reference Level Settlement Charge
RT_RLSCU	Real-Time Reference Level Settlement Charge Uplift

Acronym	Term
SIV	Start indication value
SQEW	Scheduled quantity of energy withdrawn
TR	Transmission right
TRCA	Transmission rights clearing account

– End of Section –

References

Document ID	Document Title
MDP_PRO_0002	Market Rules for the Ontario Electricity Market
PRO-408	Market Manual 1: Connecting to Ontario's Power System, Part 1.5: Market Registration Procedures
IMP_PRO_0034	Market Manual 4: Market Operations, Part 4.3: Real-Time Scheduling of the Physical Markets
MDP_PRO_0029	Market Manual 4: Market Operations, Part 4.4: Transmission Rights Auction
MDP_PRO_0030	Market Manual 4: Market Operations, Part 4.5: Market Suspension and Resumption
TBD	Market Manual 4: Market Operations, Part 4.6: Market Remediation
MDP_PRO_0034	Market Manual 5: Settlements, Part 5.3: Physical Bilateral Contracts
MDP_PRO_0035	Market Manual 5: Settlements, Part 5.6: Non-Market Settlement Programs
TBD	Market Manual 5: Settlements, Part 5.10: Settlement Disagreements
TBD	Market Manual 5.7 Settlement Process
TBD	Market Manual 5.8 Settlement Invoicing
TBD	Market Manual 5.9 Settlement Payment Methods and Schedule
TBD	Market Manual 14: Market Power Mitigation, Part 14.1: Market Power Mitigation Procedures
TBD	Market Manual 14: Market Power Mitigation, Part 14.2: Reference Level and Reference Quantity Procedures
IMP_LST_0001	IESO Charge Types and Equations

– End of Document –