Market Renewal Program: Energy

MARKET SETTLEMENT

Detailed Design

Issue 1.0

This document provides a detailed overview of the processes related to Market Settlement that will be implemented for the Energy work stream of the Market Renewal Program, including related market rule and procedural requirements.

Disclaimer

This document provides an overview of the proposed detailed design for the Ontario Market Renewal Program (MRP) and must be read in the context of the related MRP detailed design documents. As such, the narratives included in this document are subject to on-going revision. The posting of this design document is made exclusively for the convenience of *market participants* and other interested parties.

The information contained in this design document and related detailed design documents shall not be relied upon as a basis for any commitment, expectation, interpretation and/or design decision made by any *market participant* or other interested party.

The *market rules*, *market manuals*, applicable laws, and other related documents will govern the future market.

Document Change History

Issue	Reason for Issue	Date
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Related Documents

Document ID	Document Title
DES-13	MRP High-Level Design: Single Schedule Market
DES-14	MRP High-Level Design: Day-Ahead Market
DES-15	MRP High-Level Design: Enhanced Real-Time Unit Commitment
DES-16	MRP Detailed Design: Overview
DES-17	MRP Detailed Design: Authorization and Participation
DES-18	MRP Detailed Design: Prudential Security
DES-19	MRP Detailed Design: Facility Registration
DES-20	MRP Detailed Design: Revenue Meter Registration
DES-21	MRP Detailed Design: Offers, Bids, and Data Inputs
DES-22	MRP Detailed Design: Grid and Market Operations Integration
DES-23	MRP Detailed Design: Day-Ahead Market Calculation Engine
DES-24	MRP Detailed Design: Pre-Dispatch Calculation Engine
DES-25	MRP Detailed Design: Real-Time Calculation Engine
DES-26	MRP Detailed Design: Market Power Mitigation
DES-27	MRP Detailed Design: Publishing and Reporting Market Information
DES-28	MRP Detailed Design: Market Settlement
DES-29	MRP Detailed Design: Market Billing and Funds Administration

Table of Contents

Table of Contents i

List of Figures iv

List of Tables v

Table of Changes viii

1 Introduction 1

1.1 Purpose 1
1.2 Scope 1
1.3 Who Should Use This Document 2
1.4 Assumptions and Limitations 2
1.5 Conventions 2
1.6 Roles and Responsibilities 2
1.7 How This Document Is Organized 3

2 Summary of the Current and Future State 4

2.1 Market Settlement in Today's Market 4
2.2 Market Settlement in the Future Market 8

3 Detailed Functional Design 13

3.1 Structure of this Section 13
3.2 Objectives 13
3.3 Overview of Settlement Changes Under the MRP 14
3.3.1 The Day-Ahead Market Overview 14
3.3.2 The Real-Time Market Overview 15
3.4 Impact on Current Settlement Amount Calculations 16
3.5 Collection of Settlement-Ready Data 21
3.5.1 The Business Requirements of Settlement-Ready Data Processing 21
3.5.2 Collection of Registration Data 22
3.5.3 Collection of Dispatch Data from Market Participants 24
3.5.4 Collection of Day-Ahead Market Data 26
3.5.5 Collection of Pre-Dispatch Data 46
3.5.6 Collection of Real-Time Market Data 57
3.5.7 Collection of Market Integration Data 78
3.5.8 Collection of Ex-Post Data 79
3.5.9 Pseudo-Unit (PSU) Settlement Data 79

3.6 Day-Ahead and Real-Time Energy and Operating Reserve Settlement 81
3.6.1 DA and RT Energy and OR Settlement: First Settlement 81
3.6.2 DA and RT Energy and OR Settlement: Second Settlement 86
3.6.3 Non-Dispatchable Load Settlement 92
3.7 Market Charges, Credits and Uplifts 96
3.7.1 DAM Make-Whole Payment (DAM_MWP) 98
3.7.2 DAM Generator Offer Guarantee (DAM_GOG) 105
3.7.3 DAM_MWP Uplift (DAM_MWPU) 117
3.7.4 DAM Reliability Scheduling Uplift (DRSU) 117
3.7.5 Real-Time Make-Whole Payment (RT_MWP) 120
3.7.6 Real-Time Make-Whole Payment Uplift (RT_MWPU) 130
3.7.7 DAM Balancing Credit (DAM_BC) 131
3.7.8 DAM Balancing Credit Uplift (DAM_BCU) 134
3.7.9 Real-Time Generator Offer Guarantee (RT_GOG) 134
3.7.10 RT_GOG Uplift (RT_GOGU) 150
3.7.11 Generator Failure Charge (GFC) 150
3.7.12 Generator Failure Charge – Market Price Component Uplift (GFC_MPCU) 161
3.7.13 Generator Failure Charge – Guarantee Cost Component Uplift (GFC_GCCU) 161
3.7.14 Congestion Rent and Loss Residuals (CRLR) 162
3.7.15 Transmission Rights 163
3.7.16 Impacted Current Settlement Amounts 164
3.8 Market Remediation 173
3.9 Financial Neutrality 176
3.9.1 General Principles of Financial Neutrality 176
3.9.2 Neutrality 176
3.9.3 Neutrality - DAM TR Auction Process 178
3.10 Regulatory Processes 178
3.11 Settlement Reports 178
3.11.1 Settlement Statements and Data Files 178
3.11.2 Private and Public Reports 179
3.12 Notice of Disagreement and Notice of Dispute 180
3.12.1 Notice of Disagreement 180
3.12.2 Notice of Dispute 181
3.12.3 Timelines 181
3.13 Market Power Mitigation 181
3.13.1 Make-Whole Payment Impact Test 183
3.13.2 Reference Level Settlement Charges (RLSC) 186
3.13.3 Reference Level Settlement Charge Uplift (RLSCU) 188
3.13.4 Ex-Post Mitigation Settlement Charges 189
3.13.5 Ex-Post Mitigation Settlement Charge Uplift (EXP_MSCU) 190

4 Market Rule Requirements 191

5 Procedural Requirements ... 242

5.1 Market-Facing Procedural Impacts ... 242

5.2 Internal Procedural Impacts ... 252

6 Business Process and Information Flow Overview ... 254

6.1 Market-Facing Process Impacts ... 254

6.1.1 Process P1 – Calculate Energy and OR Settlement Amounts ... 256

6.1.2 Process P2 – Calculate Credits, Charges, Uplifts Settlement Amounts ... 263

6.1.3 Process P3 – Calculate TR Auction Settlement Amounts ... 274

6.1.4 Process P4 – Calculate DR Auction Settlement Amounts ... 275

6.1.5 Process P5 – Produce Settlement Statements and Data Files ... 277

6.1.6 Process P6 – Settlement Quality Control ... 283

6.1.7 Process P7 – Notice of Disagreement Process ... 284

6.1.8 Process P8 – Settlement Recalculation ... 286

6.2 Internal Process Impacts ... 287

Appendix A: Market Participant Interfaces ... 288

Market Participant Interfaces ... 288

Market Settlement Forms ... 288

Appendix B: Internal-Facing Procedural Requirements *[Internal only]* ... 289

Appendix C: IESO Internal Business Process and Information Requirements *[Internal only]* ... 290

Appendix D: Settlement Amounts ... 291

New Settlement Amounts ... 291

Existing IESO-Administered Markets Settlement Amounts ... 293

Existing Transmission Rights Market Settlement Amounts ... 295

Existing Ancillary Service Settlement Amounts ... 296

Existing Legislation-Related Settlement Amounts ... 297

References ... 299

List of Figures

Figure 1-1: Detailed Design Document Relationships.. 1
Figure 2-1: Settlement Process in the Current Market... 7
Figure 2-2: Settlement Process in the Future Market..12
Figure 3-1: Settlement Amount Balancing Groupings...177
Figure 6-1: Future Settlement Process Data Flow Diagram – Level 1 255

List of Tables

Table 2-1: Relevant Sub-Systems for Settlement-Ready Data 5
Table 3-1: Settlement Amounts in First and Second Settlement 14
Table 3-2: Amended Current Market Settlement Amounts 16
Table 3-3: Replaced Current Market Settlement Amounts...17
Table 3-4: Retired CMSC Current Market Settlement Amounts..19
Table 3-5: Retired DACP Current Market Settlement Amounts 19
Table 3-6: Replaced Current Transmission Rights Market Settlement Amounts..................20
Table 3-7: Nomenclature of Settlement Variables 22
Table 3-8: Facility Registration Data Used for Settlement 24
Table 3-9: Non-Financial Hourly and Daily Dispatch Data Used for Settlement...................24
Table 3-10: Prices Received from the DAM Calculation Engine 26
Table 3-11: Schedules Received from the DAM Calculation Engine..................................28
Table 3-12: Mitigation Results from the DAM Calculation Engine......................................30
Table 3-13: DAM Thresholds from the Market Power Mitigation Information System...........31
Table 3-14: DAM Unit Commitment Events 32
Table 3-15: Financial Dispatch Data for Physical Transactions Submitted to the DAM........36
Table 3-16: Description of DAM Offers and Bids for Virtual Transactions...........................39
Table 3-17: Description of Settlement Input Values Derived from DAM Data.......................40
Table 3-18: DAM PBC Quantities Collected by the Settlement Process 43
Table 3-19: Prices Received from the PD Calculation Engine 46
Table 3-20: Schedules Received from the PD Calculation Engine......................................48
Table 3-21: Mitigation Results from the PD Calculation Engine..49
Table 3-22: PD Thresholds from the Market Power Mitigation Information System 50
Table 3-23: PD Unit Commitment Events 50
Table 3-24: Other Data Received from the PD Calculation Engine.....................................50
Table 3-25: Financial Dispatch Data for Physical Transactions Submitted to Pre-Dispatch .53
Table 3-26: Description of Settlement Input Values Derived from PD Data 56
Table 3-27: Prices Received from the RT Calculation Engine 58
Table 3-28: Schedules Received from the RT Calculation Engine......................................60
Table 3-29: Mitigation Results from the RT Calculation Engine 62
Table 3-30: RT Thresholds from the Market Power Mitigation Information System..............63
Table 3-31: Commitment Information from the RT Calculation Engine 64
Table 3-32: Other Data Used for Settlement 64
Table 3-33: Financial Dispatch Data for Physical Transactions Submitted to the Real-Time Market..64
Table 3-34: Revenue Metering Data Received from the Meter Data Management System .68

Table 3-35: Description of Settlement Input Values Derived from RT Data..........................69
Table 3-36: RT PBC Quantities Collected by the Settlement Process 77
Table 3-37: Derived Data for Pseudo-Units 80
Table 3-38: Settlement Amounts in the First Settlement..81
Table 3-39: Resolution of HPTSA{1} Calculation...82
Table 3-40: Eligibility for HPTSA in First Settlement 82
Table 3-41: Resolution of HVTSA{1} Calculation...84
Table 3-42: Eligibility for HVTSA in First Settlement 85
Table 3-43: Resolution of HORSA{1} Calculation 85
Table 3-44: Eligibility for HORSA in First Settlement 86
Table 3-45: Settlement Amounts in the Second Settlement...87
Table 3-46: Resolution of HPTSA{2} 87
Table 3-47: Eligibility for HPTSA in Second Settlement...88
Table 3-48: Resolution of HVTSA{2} Calculation...90
Table 3-49: Eligibility for HVTSA in Second Settlement...90
Table 3-50: Resolution of HORSA{2} 91
Table 3-51: Eligibility for HORSA in Second Settlement 91
Table 3-52: Resolution of NDL Calculations 94
Table 3-53: Settlement Amounts Calculated Following DAM...96
Table 3-54: Intertie Reason Codes and their Eligibility for MWP and Intertie Failure Charges 97
Table 3-55: Resolution of DAM_MWP Calculations...99
Table 3-56: Resolution of DAM_GOG Calculations 105
Table 3-57: Eligibility to Recover Implied Cost of Start-Up Offers.....................................106
Table 3-58: Resolution of DAM Reliability Scheduling Uplift Calculation...........................118
Table 3-59: Resolution of RT_MWP Calculations..121
Table 3-60: Resolution of DAM_BC Calculations 131
Table 3-61: Resolution of Real-Time GOG Calculation 135
Table 3-62: Eligibility to Recover Implied Cost of Start-Up Offers......................................136
Table 3-63: Eligibility to Recover Implied Cost of PSU Start-Up Offers..............................142
Table 3-64: Resolution of Generator Failure Charge Calculation.......................................150
Table 3-65: Types of Failure and Periods Subject to Failure Charge Assessment.............151
Table 3-66: Types of Failure and Periods Subject to Failure Charge Assessment for a Pseudo-Unit 155
Table 3-67: Resolution of Real-Time Intertie Failure Charge Calculation...........................165
Table 3-68: Resolution of RT_IOG Calculation..168
Table 3-69: Resolution of RT_RDSA Calculation 170
Table 3-70: Reports Produced by the Settlement Process 179
Table 3-71: Calendars Produced by the Settlement Process...180

Table 3-72: Settlement Values 180
Table 3-73: Resolution of Reference Level Settlement Charge Calculation....................187
Table 3-74: Persistence Multipliers....................188
Table 4-1: Market Rules Impacts....................191
Table 5-1: Impacts to Market-Facing Procedures....................243
Table 6-1: Process P1 Input and Output Data Flows....................256
Table 6-2: Process P2 Input and Output Data Flows....................264
Table 6-3:Process P3 Input and Output Data Flows....................274
Table 6-4: Process P4 Input and Output Data Flows....................275
Table 6-5: Process P5 Input and Output Data Flows....................278
Table 6-6: Process P6 Input and Output Data Flows....................284
Table 6-7: Process P7 Input and Output Data Flows....................285
Table 6-8: Process P8 Input and Output Data Flows....................286

Table of Changes

Reference (Section and Paragraph)	Description of Change

1 Introduction

1.1 Purpose

This document is a section of the Market Renewal Program (MRP) detailed design document series specific to the Energy work stream. This document provides the details of the business design and the requirements for *market rules*, market facing and internal procedures, and the data flow required to support the Market Settlement process as related to the introduction of the future day-ahead market and *real-time market*. This design document will aid the development of user requirements, business processes, *market rules* and supporting systems.

As illustrated in Figure 1-1, this document is part of the MRP detailed design document series and will provide the design basis for the development of the governing documents and the design documents.

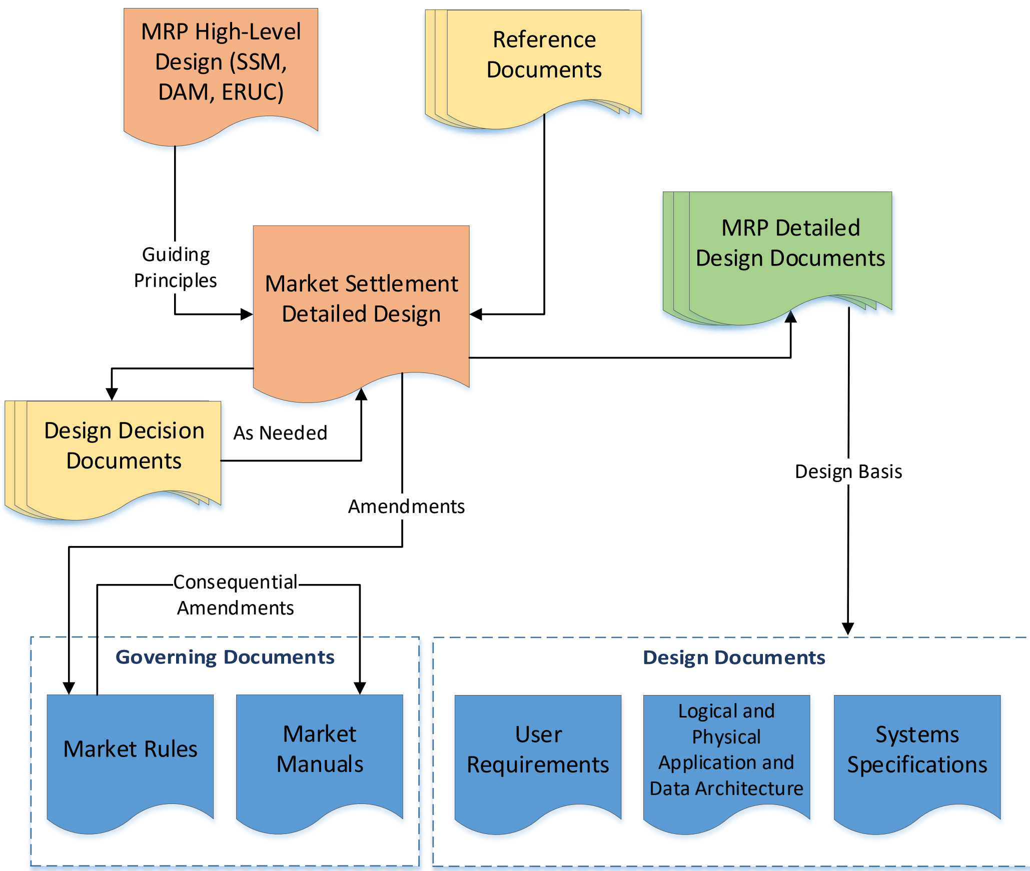

Figure 1-1: Detailed Design Document Relationships

1.2 Scope

This document describes the Market Settlement process requirements in the future day-ahead market and *real-time market* in terms of:

- detailed functional design;

- supporting *market rule* requirements;
- supporting procedural requirements; and
- business process and information flow requirements.

Various portions of this document make reference to current business practices, rules, procedures and processes of Market Settlement. However, this document is not meant as a restatement of the existing design of *the Independent Electricity System Operator (IESO)* process. Rather this document focuses on existing components only to the extent that they might be used in the current or amended form in support of the future day-ahead market and *real-time market*.

1.3 Who Should Use This Document

This document is a public document for use by the MRP project team, pertinent *IESO* departments and external stakeholders. Portions of this document that are only pertinent to *IESO* internal processes and procedures may not be incorporated into the public version.

1.4 Assumptions and Limitations

Assumptions:

While this document makes references to specific parameters that might be used in the Market Settlement process, this document may not determine what the value of all those parameters might ultimately be. The value of such parameters will be determined through the development of the *market rules* and *market manuals.*

Limitations:

The business process design presented in Sections 2 and 6 of this document provides a logical breakdown of the various sub-processes described in the detailed functional design presented in Section 3. However, factors such as existing and future system boundaries and system capabilities may alter the ultimate design of these sub-processes.

All *settlement amounts* presented in this document illustrate that amounts owed to the market net out to the amount owed from the market. The ultimate form of their presentation on *settlement statements* may vary from the descriptions provided in this document.

1.5 Conventions

The standard conventions followed for this document are as follows:

- Title case is used to highlight process or component names; and
- Italics are used to highlight *market rule* terms that are defined in Chapter 11 of the *market rules*.

1.6 Roles and Responsibilities

This document does not set any specific roles or responsibilities. This document provides the design basis for development of the documentation associated with the *IESO* Project Lifecycle that will be produced in conjunction with the MRP.

1.7 How This Document Is Organized

This document is organized as follows:

- **Section 2** of this document briefly describes the current context of the Market Settlement process, and its future context for the future day-ahead market (DAM) and *real-time market* (RTM);
- **Section 3** of this document provides a detailed description of the functional design inferred from the *settlement* sections of the Day-Ahead Market (DAM), Enhanced Real-Time Unit Commitment (ERUC) and Single Schedule Market (SSM) high-level design documents;
- **Section 4** of this document describes how the *settlement processes* will be enabled under the authority of the *market rules* in terms of existing rule provisions, amended rule provisions, and additional rule provisions that will need to be developed;
- **Section 5** of this document describes the requirements of the Market Settlement process for a system of market-facing and internal procedures including existing procedures, amended procedures, and additional procedures that will need to be developed; and
- **Section 6** of this document provides an overview of the arrangement of *IESO* processes supporting the overall Market Settlement process described in Section 3. This section also outlines the logical boundaries and interfaces of the various sub-processes related to the Market Settlement process in terms of existing processes, amended processes and additional processes that will need to be developed.

– End of Section –

2 Summary of the Current and Future State

2.1 Market Settlement in Today's Market

Today's *energy market* employs a two-schedule market design providing a uniform market clearing price that is used to establish the province-wide *hourly Ontario energy price* (HOEP). The two-schedule market design gives rise to divergence between prices and schedules and requires the *settlement* calculation of congestion management settlement credit (CMSC) payments and related uplifts together with payments for *energy* and *operating reserve*.

The existing Day-Ahead Commitment Process (DACP) is not a market process and thus does not generate prices and related schedules. Rather, the DACP is a *reliability* process that the *IESO* uses to schedule and commit resources a day in advance. The DACP utilizes three-part offers providing *start-up costs* and *speed no-load costs* and supports the day-ahead production cost guarantee (DA-PCG) and real-time generation cost guarantee (RT-GCG) programs. The existing *settlement process* is used to calculate the DA-PCG and RT-GCG payments for eligible non-quick start (NQS) *generation units* together with related uplifts and debits.

The existing *settlement process* also supports the *settlement* of *demand response capacity obligations* awarded to *demand response market participants.*

Financial *transmission rights* (FTRs) are *settled* at *real-time market* prices for *intertie* transactions.

From a market-facing standpoint, the primary service that the *settlement process* delivers is a detailed breakdown of all the financial calculations performed by the *IESO* concerning a *market participant's* activity in the *IESO-administered markets* including the *real-time market*, *demand response auction*, *TR market*, and *procurement markets*. This service allows *market participants* to review and reconcile these calculations and pursue any apparent disagreements over such calculations with the *IESO*. This review and reconciliation is accomplished through the issuance to *market participants* of *preliminary settlement statements* and *final settlement statements* and related data files for each *dispatch day* together with invoicing of all *settlement amounts*.

Figure 2-1 illustrates the overall context of the current *settlement process*. This includes information flows directly between the *settlement process* and *market participants* and information flows between the *settlement process* and other internal *IESO* processes.

The current services *offered* to *market participants* through the *settlement process* include:

- *Preliminary* and *final settlement statements* and data files to confirm *real-time market settlement* calculations and all the underlying data used by the *settlement process*;
- *Preliminary* and *final settlement statements* related to the auction of *TRs*;
- Provision of reconciliation data specific to *transmission tariffs*;
- Provision of reconciliation data concerning government rate caps and other regulated charges;
- *Settlement* of *demand response capacity obligations* delivered by *dispatchable loads* and *hourly demand response* resources;
- A structured process for receiving, resolving and/or escalating *notices of disagreement* (NoDs) and *settlement*-related disputes;

- A series of information flows between the *IESO* and *market participants* to facilitate the reconciliation of programs outlined in the *market rules* including, but not limited to, the RT-GCG Program; and
- The ability to influence *settlement* outcomes through the submission of:
  - *Physical Bilateral Contract* (PBC) *data*; and
  - Data supporting the implementation of government-regulated rate structures including, but not limited to, the Regulated Price Plan and Global Adjustment.

For the most part, the above services will continue to be provided after the MRP is implemented. In some cases, these services will be revised or expanded to include the various *settlement* requirements of the MRP.

As illustrated in Figure 2-1, the *settlement process* also uses information services from other *IESO* processes. Most importantly, this includes the provision of *settlement*-ready data from a variety of upstream processes. Table 2-1 lists the *settlement*-ready data that is received from other relevant sub-systems.

Table 2-1: Relevant Sub-Systems for Settlement-Ready Data

Settlement-Ready Data	Relevant Sub-System
Day-Ahead Commitment Process data	• Day-Ahead Optimization System (DAOS)
Revenue Metering data	• Meter Data Management System (MDMS)
Transmission Tariff Demand measurements	• Transmission Tariff Demand Calculator
Market schedules, uniform Ontario prices and *intertie zone* prices	• Market Interface System (MIS)
Constrained schedules	• Market Interface System (MIS)
Import/export transaction details	• Dispatch Data Management System (DDMS) Interchange Scheduler (IS)
Transmission Rights (*TR*) prices and quantities	• Transmission Rights Auction (TRA)
Registration data	• Registration in Customer Data Management System (CDMS)
Offers and *bids* data and *physical bilateral contract* (PBC) *data*	• Market Information Management (MIM) • Energy Market Interface (EMI) • Energy Market Administration Tool (EMAT)
Data supporting the implementation of government-regulated rate structures (i.e. Global Adjustment)	• Online IESO

The term *settlement*-ready is used to describe the state of data received by the *settlement process,* which means that no further modification or intervention is required for such data before it is used to perform the calculation of *settlement amounts*. This term will be used in all aspects of describing the receipt of data by the *settlement process* in the context of MRP. Only residual corrections to such data are addressed by the *settlement process* as part of the *notice of disagreement* (NoD) process.

Finally, as illustrated in Figure 2-1, information of significant importance to the detailed design of Market Settlement from the *settlement process* are utilized by the following systems and processes:

- The IESO Funds Administration System;
- The Prudential Security process;
- The Surveillance Data Repository;
- Settlement Department Users;
- Administration of Contracts and Agreements for various *ancillary services;*
- Administration of Procurement Contracts and Conservation Programs;
- Inadvertent Energy Reporting to NPCC;
- Transmission Rights Auction; and
- Information for downstream publication of aggregated settlement results to the marketplace.

Section 2.2 provides an overview of how these outbound information flows will be affected by the implementation of the MRP.

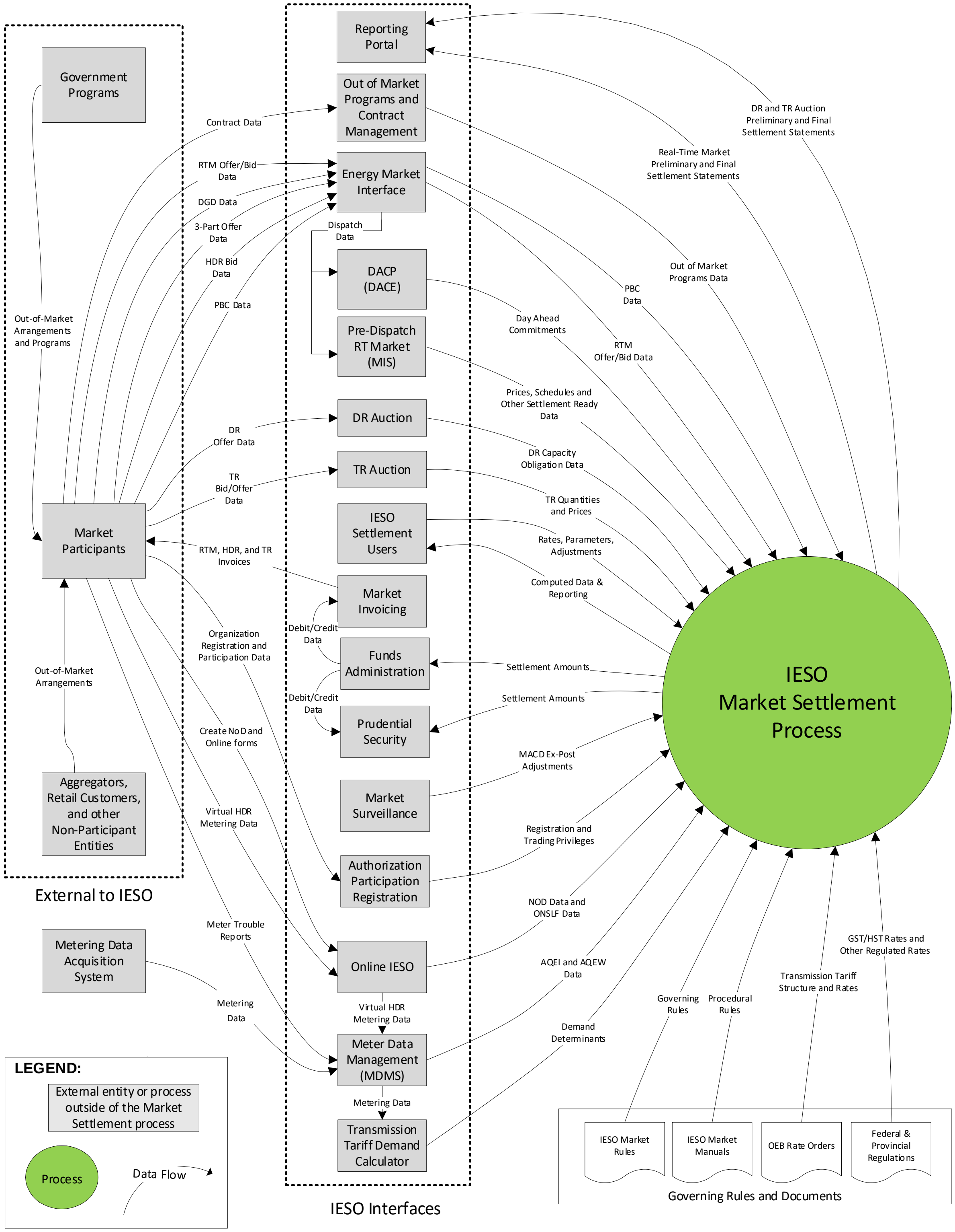

Figure 2-1: Settlement Process in the Current Market

2.2 Market Settlement in the Future Market

MRP will introduce a day-ahead market (DAM) for physical *energy* and operating *reserve* transactions, and virtual energy transactions, together with a *real-time market* (RTM). Both the day-ahead market and *real-time market* will employ a single schedule market design including locational marginal prices (LMP).

In a single schedule market, *dispatch* schedules and LMPs are significantly impacted by *offer* prices and other financial *dispatch data* parameters. To mitigate the impact of the exercise of market power, the *IESO* will implement a framework of ex-ante mitigation actions (applied prior to the determination of *dispatch* schedules, market prices, and market *settlement*) and ex-post mitigation actions (applied after the *settlement* of *energy* and *operating reserve* markets). The ex-ante mitigation of price impact and *settlement* mitigation of make-whole payment impact may result in the replacement of as-submitted *dispatch data* values that fail mitigation conduct or impact tests with mitigated reference level data for the failed *dispatch data* parameters. Such mitigated *dispatch data* will be used in the *settlement process* for the calculation of *energy*, *operating reserve*, make-whole payments, and other guarantee payment *settlement amounts*.

Settlement of DAM and RTM *energy* and *operating reserve* using as-submitted or mitigated *dispatch data* will be accomplished through a two-*settlement* system for dispatchable *facilities*. *Settlement* of *energy* for *non-dispatchable loads* will be based on the actual *energy* withdrawn in real-time and the day-ahead market Ontario zonal price adjusted for load forecast deviations.

Changes to market payments, charges, credits and uplifts will be impacted by the future day-ahead market and *real-time market*. Notably CMSC payments and associated uplifts will be eliminated, as will generation cost guarantee payments and related recovery debits. New market charges, credits, guarantees, make-whole payments and uplifts are identified and defined in Section 3.7 of this design document along with the required changes to current *settlement amounts* that will continue to be used in the future *energy market*.

Review and reconciliation of *settlement amounts* will continue to be accomplished through the issuance to *market participants* of *preliminary settlement statements* and *final settlement statements* and related data files for each *dispatch day* together with invoicing of all *settlement amounts* in accordance with the current market *settlement process*.

The *settlement process* will continue to support any necessary recalculations pertaining to the current market.

Settlement of *demand response capacity obligations* will remain unchanged.

Financial *transmission rights* (FTRs) will be *settled* based on day-ahead market LMPs.

The future day-ahead market will provide for the necessary day-ahead *reliability* needs through the commitment of resources a day in advance. Therefore, the DACP and the associated DA-PCG and RT-GCG programs will be retired.

The DA-PCG will be replaced by a DAM Generator Offer Guarantee (DAM_GOG) for eligible NQS *generation units* that are committed by the DAM calculation engine. The RT-GCG will be replaced by a Real-Time Generator Offer Guarantee (RT_GOG) for eligible NQS *generation units* committed during the pre-dispatch timeframe.

The future day-ahead market and *real-time market* will also provide for DAM make-whole payments (DAM_MWP) and real-time make-whole payments (RT_MWP) for dispatchable supply and load resources that are scheduled in the day-ahead market or dispatched in the *real-time market* when such schedules or *dispatch* may result in implied losses.

The new *settlement*-ready information flows into the *settlement process* are summarized below:

- **New Data from the Day-Ahead Market process**. This new information flow will include:
    - DAM nodal and zonal LMPs for *energy* and *operating reserve*;
    - DAM schedules for *energy, operating reserve* and virtual quantities;
    - Hourly and daily *dispatch data* used by the DAM calculation engine including *offers* and *bids*;
    - *Dispatch data* mitigated by the DAM calculation engine on failure of ex-ante conduct tests;
    - Market power mitigation ex-ante conduct and price impact test data including prevailing constrained area mitigation conditions;
    - Market power mitigation reference level data used by or available to the DAM calculation engine;
    - DAM unit commitment events;
    - DAM quantity of *energy* scheduled by the DAM calculation engine for withdrawal at *delivery points* for all *non-dispatchable loads*;
    - DAM PBC data; and
    - *Outage* and de-rate information.

New *dispatch data* parameters resulting from resource modelling for hydroelectric resources in DAM will also be required.

- **New Data from the Pre-Dispatch Process**. This new information flow will include:
    - Pre-dispatch advisory nodal LMPs;
    - Hourly and daily *dispatch data* used by the PD calculation engine including *offers* and *bids*;
    - *Dispatch data* mitigated by the PD calculation engine on failure of ex-ante conduct tests;
    - Market power mitigation ex-ante conduct and impact test data including prevailing constrained area mitigation conditions;
    - Market power mitigation reference level data used by or available to the PD calculation engine; and
    - Pre-dispatch unit commitment events.
- **New Data from the Real-Time Market Process**: This new information flow will include:
    - Real-time prices including locational marginal prices (LMP) nodal, zonal and *intertie settlement* price for *energy* and *operating reserve;*
    - Real-time locational marginal prices for *energy* at *delivery points* for all *non-dispatchable loads;*
    - Hourly and daily *dispatch data* used by the real-time (RT) calculation engine including *offers* and *bids*;
    - *Dispatch data* mitigated by the RT calculation engine on failure of ex-ante conduct tests;
    - Market power mitigation ex-ante conduct and impact test data including prevailing constrained area mitigation conditions;
    - Market power mitigation reference level data used by or available to the RT calculation engine; and
    - Outage and de-rate information impacting the maximum operation limit.

Key revisions to information flows into the *settlement process* include:

- **Market Integration and Ex-Post Data**: Key revisions include:
    - Market Integration data:
        - Interchange Scheduler (IS) reason codes and failure charge codes including new reason codes and failure charge codes due to MRP
    - Ex-Post data:
        - Market failures and errors. The *settlement process* must be informed of all calculation engine failures and errors in the day-ahead market through to real-time;
        - Ex-post mitigation charges and persistence multipliers for physical withholding; and
        - Ex-post mitigation charges for economic withholding on uncompetitive *interties*.
- **Registration Data**:
    - Virtual transaction zonal trading entities;
    - Election data, when *market participants* with a registered *non-dispatchable load* (NDL) elect to change the *facility* registration to a price responsive load; and
    - *Facility* classification as a price responsive load.
- ***Notices of Disagreement* (NoD):** All NoDs will be integrated into the current NoD process;
- ***Governing* Rules**: *Market rule* requirements governing *settlement* calculations, rights, and obligations will need to be expanded to include the *settlement* activities of the renewed market. These requirements will further be described in Section 4 of this document;
- **Procedures**: Procedures affecting both the internal workings of the *settlement process* and *market participant* will need to encapsulate MRP requirements. These requirements will further be described in Section 5 of this document; and
- **Government Regulations**: The *settlement process* will need to apply harmonized sales tax (HST) decision rules regarding new *settlement* amounts.

The changes due to MRP will also affect a number of new and existing information flows from the *settlement process,* including:

- **DAM TR Settlement Statements**: These *settlement statements* include *settlement* amounts related to the auction of DAM *TRs*. They are the same *settlement statements* issued to support today's real-time *TR market*, which will be replaced by DAM *TRs*;
- **Preliminary and Final Settlement Statements and Data Files**: The *settlement statements* and data files currently issued to support *real-time market* activities will also support the day-ahead market and changes under MRP related to the new *settlement amounts* and the relevant data requirements;
- **Settlement Data Feeds to Funds Administration, Prudential Process and the Surveillance Process**: Each of these downstream processes is effectively a "user' of *settlement* data, either at a detailed or summary level. In all cases, new *settlement amounts* will need to be integrated into these data feeds; and
- **Settlement Reports**: The *settlement process* produces several reports and publishes several *settlement* values that are made available to *market participants*. Modifications will be

required as a result of changes to *energy* pricing and *settlement amounts* (new, amended, replaced or retired).

Many of the inputs to and outputs from the *settlement process* will be affected by the implementation of MRP. Figure 2-2 summarizes each of these new or modified information flows and provides a revised context diagram illustrating these new and modified information flows in the *settlement process* after the implementation of the future day-ahead market and *real-time market*.

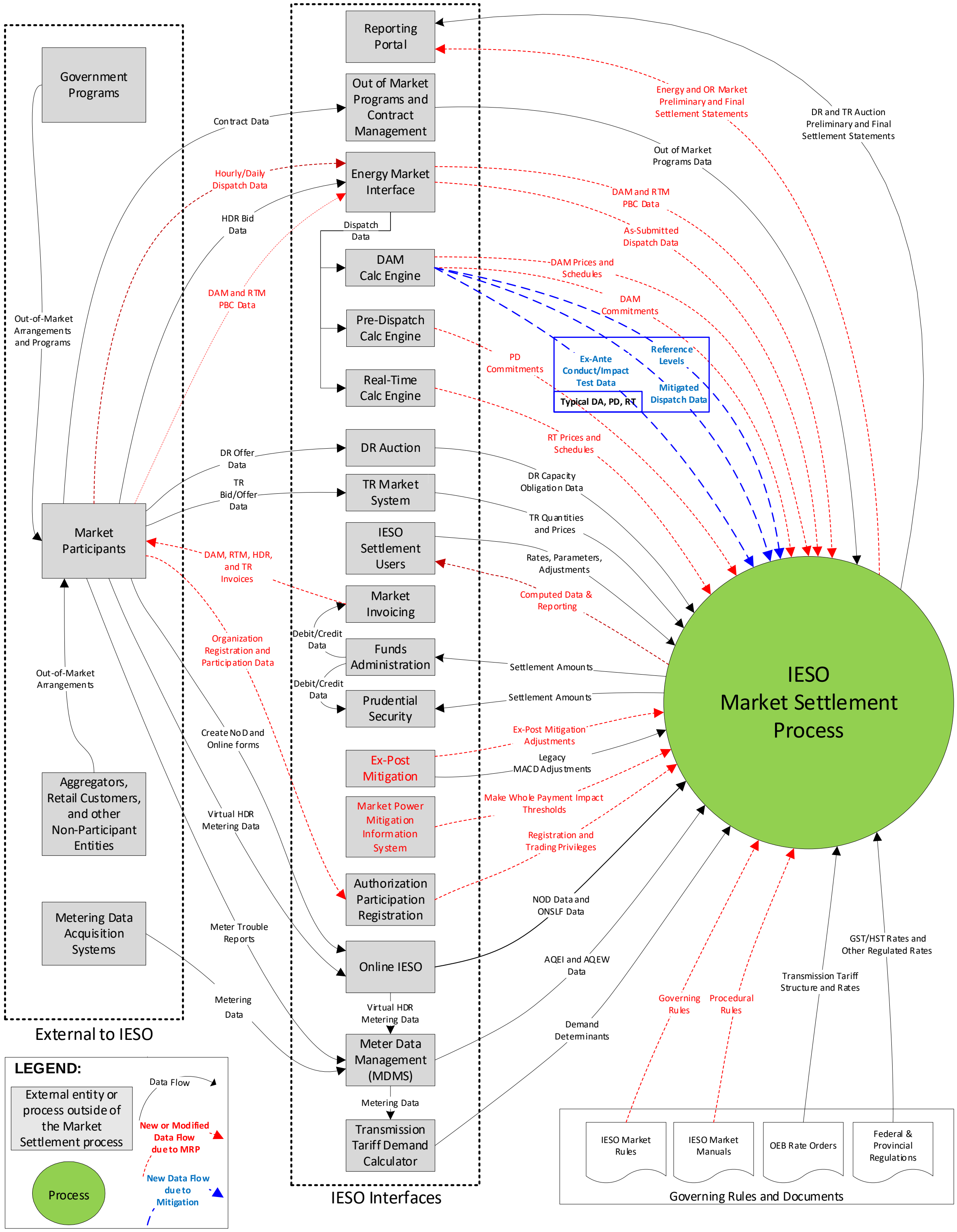

Figure 2-2: Settlement Process in the Future Market

– End of Section –

3 Detailed Functional Design

3.1 Structure of this Section

This section is divided into sub-sections pertaining to the major topic areas that are of particular interest to the *settlement process*. Over the course of this section, the design of the *settlement process* will successively be discussed in terms of:

- Objectives;
- Overview of Settlement Changes Under the MRP;
- Impact on Current Settlement Amount Calculations;
- Collection of Settlement-Ready Data;
- Day-Ahead and Real-Time Energy and Operating Reserve Settlement;
- Market Charges, Credits and Uplifts;
- Market Remediation;
- Financial Neutrality;
- Regulatory Processes;
- Settlement Reports;
- Notice of Disagreement and Notice of Dispute; and
- Market Power Mitigation.

The above sub-sections generally cover the major topic areas of the MRP high-level designs, and specifically, the design of the *settlement process* in the context described in Section 2 of this document.

3.2 Objectives

The key objective of the *settlement process* design is the continuity of existing practices that have served the *IESO* and *market participants* well since market opening. The specific practices include:

- Providing timely and accurate *settlement statements*: For each *trading day* with the issuance of a *preliminary settlement statement*, an associated NoD window/process will be triggered, followed by the issuance of a *final settlement statement*;
- Ensuring availability of data for *market participant* reconciliation: To allow *market participants* to reconcile their *settlement statements* in an accurate and timely manner, the applicable data will be provided in accordance with information confidentiality guidelines; and
- Ensuring timely availability of revenue meter data: Revenue *metering data* regarding the *market participant's* physical consumption or delivery will be made available in accordance with current market timelines. This provides *metered market participants* the data necessary to fulfil their obligation to notify the *IESO* of any *metering data* or *metering installation* problems prior to *settlement*.

3.3 Overview of Settlement Changes Under the MRP

This design document provides clarity for *settlement* under MRP by including the equations used for *settlement* calculations, but may not address every circumstance.

3.3.1 The Day-Ahead Market Overview

The day-ahead market will introduce a two-*settlement* system for *energy* and *operating reserve* that is designed to encourage greater and more efficient market participation. The two-*settlement* system allows the *real-time market* to function as a balancing market to reconcile day-ahead market *settlement amounts* for *energy* and *operating reserve* with *real-time market* results.

Under this approach, the *settlement* of *energy* and *operating reserve* will be based upon first *settlement* and second *settlement*, which are defined as follows:

- **First *settlement*** *amounts* are produced at the first stage of the two-*settlement* system. It includes *settlement amounts* for *energy* and *operating reserve* that can be calculated on the basis of *settlement* data from the DAM calculation engine.
- **Second *settlement*** *amounts* are produced at the second stage of the two-*settlement* system. It includes the *settlement amounts* that can be calculated on the basis of *settlement* data from the DAM calculation engine reconciled with the *real-time market* results.

Under the two-*settlement* system, the *settlement amounts* will be processed as follows:

- The *settlement* amounts for virtual transactions and physical transactions under the first and second *settlement* will be provided to *market participants* via *preliminary settlement statements* and *final settlement statements* issued 10 and 20 *business days* after the real-time *trading day*, respectively;
- The combination of the first *settlement* and the second *settlement* will replace the Net Energy Market Settlement Credit (NEMSC) for *generation facilities* and *dispatchable loads*; and
- All calculations reported on a *preliminary settlement statement* may be subject to the NoD process.

The first and second *settlement amounts* are summarized in **Table 3-1**. Refer to Section 3.6 – Day-Ahead and Real-Time Energy and Operating Reserve Settlement for more details on the *settlement* calculations of these *settlement amounts.*

Table 3-1: Settlement Amounts in First and Second Settlement

First Settlement Amount	Second Settlement Amount
Hourly Physical Transaction Settlement Amount (HPTSA{1})	Hourly Physical Transaction Settlement Amount (HPTSA{2})
Not applicable	Hourly Physical Transaction Settlement Amount – Non-Dispatchable Load (HPTSA_NDL)
Hourly Virtual Transaction Settlement Amount (HVTSA{1})	Hourly Virtual Transaction Settlement Amount (HVTSA{2})
Hourly Operating Reserve Settlement Amount (HORSA{1})	Hourly Operating Reserve Settlement Amount (HORSA{2})
Not applicable	DAM Operating Reserve Uplift (DORU)

The two-*settlement* system will apply to *market participants* participating in the day-ahead market, including price responsive loads.

The two-*settlement* system will not be applied to *non-dispatchable loads* (NDLs). The *IESO* will continue to provide the *demand* forecast for NDLs and will settle each such *load facility* based on the real-time allocated quantity of *energy* withdrawn and the hourly day-ahead Ontario zonal price adjusted for the cost/benefit of any load forecast deviation. This calculation is explained in further detail in Section 3.6.3 – Non-Dispatchable Load Settlement. This process will result in *market participants* receiving a *settlement amount* for *non-dispatchable loads* based on the actual quantity of *energy* consumed in real-time. The Hourly Physical Transaction Settlement Amount for *non-dispatchable load* (HPTSA_NDL) will replace the NEMSC for *non-dispatchable load*.

Congestion rent and loss residuals collected from internal system congestion in the day-ahead market and the *real-time market* will be distributed to all loads. Congestion rents collected from *intertie* congestion will continue to fund the *TR market*. *TRs* in the *real-time market* will be replaced with DAM TRs.

The DAM make-whole payment (DAM_MWP) provides a *settlement amount* to dispatchable *generation facilities*, *dispatchable loads*, price responsive loads, and *boundary entities* that are scheduled in the day-ahead market when the *market participant* would otherwise incur an implied loss. A payment may occur when the *energy* and *operating reserve* revenue earned is insufficient to recover *offer* costs or *bid* benefits for *energy* and *operating reserve*. The DAM_MWP will be subject to the mitigation process.

With the replacement of DACP, the Day-Ahead Production Cost Guarantee (DA-PCG) will be replaced by the DAM Generator Offer Guarantee (DAM_GOG). All NQS *generation facilities* committed by the DAM calculation engine will have their costs covered by the DAM_GOG when their DAM revenues from the *energy market* and *operating reserve market* are insufficient to cover these costs. The DAM_GOG payment will be subject to the mitigation process.

The day-ahead market will also introduce a new type of uplift payment known as the DAM Reliability Scheduling Uplift (DRSU). This uplift will recover the cost of committing additional *registered facilities* in the *reliability* scheduling pass of the DAM calculation engine from virtual supply transactions, loads and exports. As stated in the DAM high-level design, virtual supply transactions may cause additional physical resources to be committed or imports to be scheduled in the *reliability* scheduling pass of the DAM calculation engine.

In addition, any residual make-whole payment costs not allocated to virtual supply transactions would be the result of the *IESO* over-forecasting load in the *reliability* scheduling pass of DAM. These residual costs will be recovered proportionately from real-time loads and exports, as they are today, based on their real-time consumption.

3.3.2 The Real-Time Market Overview

In addition to functioning as a balancing market for *energy* and *operating reserve* under the two-*settlement* system, the *real-time market* and enhanced real-time unit commitment may re-dispatch and commit additional *registered facilities* to meet changing demand in real-time or changes in system conditions during the pre-dispatch period.

Registered generation facilities that require a long start-up time and that are committed in the pre-dispatch timeframe will be provided a Real-Time Generator Offer Guarantee (RT_GOG) if they are unable to cover their costs associated with *energy*, start-up and speed no-load *offers* and *operating reserve offers* through the revenues earned in real-time. The RT_GOG payment will replace the Real-Time Generation Cost Guarantee (RT-GCG) payment available in the current *real-time market*. The RT_GOG will be subject to the mitigation process.

The future *real-time market* will introduce a new failure charge that will be applicable to those *generation facilities* that are committed in the pre-dispatch timeframe. *Generation facilities* that fail to meet their binding PD commitment in real time may incur a generator failure charge (GFC) due to the additional costs incurred by the market as a result of the failure. A failure charge is not applicable to a financially binding DAM schedule; the two-*settlement* system provides adequate incentives to ensure the DAM commitment is met.

Furthermore, NQS *generation facilities* and all other dispatchable *generation facilities* that deviate from their *dispatch instructions* in order to meet a *reliability* need will be compensated by receiving a Real-Time Make-Whole Payment (RT_MWP) if they are financially affected by following the *IESO dispatch instructions*. However, these facilities will be required to satisfy eligibility rules to qualify for RT_MWP. The RT_MWP will be subject to the mitigation process.

3.4 Impact on Current Settlement Amount Calculations

The implementation of MRP will introduce new *settlement amounts.* Some existing *settlement amounts* will be affected by the implementation of the DAM, and in these instances, those *settlement amounts* may be amended, replaced entirely, or will be retired under MRP. The new MRP *settlement amounts*, which will replace current *settlement amounts*, will take into account both day-ahead market and *real-time market* activity. These changes will not affect the financial outcomes of those *market participants* choosing to participate solely in the *real-time market.*

The tables that follow summarize the impact of MRP on existing *settlement amounts*. Any *settlement amounts* not listed in any of these tables will continue in their present form and usage after implementation of MRP. For a complete listing of the impact of MRP on existing *settlement amounts*, detailed by *charge type* number, refer to Appendix D – Settlement Amounts. There will be a period of time where *market participants* will continue to see existing *settlement amounts* on their *settlement statements* that will not be required in the future market as the *IESO* transitions from the current market to the future market.

Following the first *settlement* and second *settlement* of the two-*settlement* system, there will be day-ahead market and *real-time market* charges, credits and uplifts that need to be applied to ensure financial neutrality. These *settlement amounts* will appear on the *preliminary* and *final settlement statements*, along with the *settlement amounts* calculated in the first *settlement* and second *settlement* of the two-*settlement* system. All regulatory and transmission tariff *settlement amounts* will be unaffected by the changes to the *real-time market*.

Table 3-2 lists all current market *settlement amounts* that will be amended and continue in the future market.

Table 3-2: Amended Current Market Settlement Amounts

Current Market Settlement Amount	Future Market Settlement Amount	Section Reference
Generation Station Service Rebate (GSSR) *Market rules* reference: Chapter 9, Section 2.1A.9	Amended to reflect new DAM and RTM *settlement amounts* for uplifts.	3.7.16

Table 3-3 lists all current market *settlement amounts* that will be replaced with a future market *settlement amount*. These *settlement amounts* will not be required in the future market and will be retired upon implementation of MRP.

Table 3-3: Replaced Current Market Settlement Amounts

Current Market Settlement Amount	Future Market Settlement Amount	Section Reference
Net Energy Market Settlement Credit (NEMSC) *Market rules* reference: Chapter 9, Section 3.3	Replaced by first and second *settlement* of Hourly Physical Transaction Settlement Amount (HPTSA{1} and {2}) and NDL *settlement* of HPTSA	3.6.1{1} 3.6.2{2}
Hourly Uplift (HUSA) – NEMSC component *Market rules* reference: Chapter 9, Section 3.9	Replaced by first and second *settlement* of Hourly Physical Transaction Settlement Amount (HPTSA{1} and {2}) and NDL *settlement* of HPTSA	3.6.1{1} 3.6.2{2}
Operating Reserve Settlement Credit (ORSC) *Market rules* reference: Chapter 9, Section 3.4	Replaced by first and second *settlement* of Hourly Operating Reserve Settlement Amount (HORSA {1} and {2})	3.6.1{1} 3.6.2{2}
Hourly Uplift (HUSA) – Operating Reserve component *Market rules* reference: Chapter 9, Section 3.9	Replaced by DAM Operating Reserve Uplift (DORU)	3.6.2
Operating Reserve Shortfall Settlement Debit (ORSSD) *Market rules* reference: Chapter 9, Section 3.8	Replaced by Real-Time Operating Reserve Shortfall Debit (RT_ORSD)	3.7.16
Hourly Uplift (HUSA) – Operating Reserve Shortfall Settlement Debit component *Market rules* reference: Chapter 9, Section 3.9	Replaced by Real-Time Operating Reserve Shortfall Debit Uplift (RT_ORSDU)	3.7.16
Generation Cost Guarantee Payment *Market rules* reference: Chapter 9, Section 4.7B	Replaced by Real-Time Generator Offer Guarantee (RT_GOG)	3.7.9
Generation Cost Guarantee Recovery Debit *Market rules* reference: Chapter 9, Section 4.8	Replaced by Real-Time Generator Offer Guarantee Uplift (RT_GOGU)	3.7.10
Day-Ahead Production Cost Guarantee *Market rules* reference: Chapter 9, Section 4.7D	Replaced by DAM Generator Offer Guarantee (DAM_GOG)	3.7.2
Day-Ahead Production Cost Guarantee Reversal *Market rules* reference: Chapter 9, Section 4.7D.6	Replaced by DAM Generator Offer Guarantee (DAM_GOG)	3.7.2

Current Market Settlement Amount	Future Market Settlement Amount	Section Reference
Day-Ahead Production Cost Guarantee Recovery Debit *Market rules* reference: Chapter 9, Section 4.8.1.12	Replaced by DAM Make-Whole Payment Uplift (DAM_MWPU)	3.7.3
Intertie Offer Guarantee Settlement Credit *Market rules* reference: Chapter 9, Section 3.8A	Replaced by Real-Time Intertie Offer Guarantee (RT_IOG). Future market *settlement amount* will reflect applicability in real-time only.	3.7.16
Real-Time Import Failure Charge (RT_IFC) *Market rules* reference: Chapter 9, Section 3.8C	Replaced by Real-Time Import Failure Charge (RT_IMFC). Future market *settlement* amount will reflect new *intertie* congestion pricing rules – price at the internal node equivalent to the *intertie*.	3.7.16
Real-Time Export Failure Charge (RT_EFC) *Market rules* reference: Chapter 9, Section 3.8C	Replaced by Real-Time Export Failure Charge (RT_EXFC). Future market *settlement* amount will reflect new *intertie* congestion pricing rules – price at the internal node equivalent to the *intertie*.	3.7.16
Additional Compensation for Administrative Pricing Credit *Market rules* reference: Chapter 7, Section 8.4A	Replaced by Real-Time Make-Whole Payment (RT_MWP)	3.7.5 3.8
Additional Compensation for Administrative Pricing Debit *Market rules* reference: Chapter 7, Section 8.4A	Replaced by Real-Time Make-Whole Payment Uplift (RT_MWPU)	3.7.6 3.8
Ramp-Down Settlement Amount (RDSA) *Market rules* reference: Chapter 9, Section 3.5A	Real-Time Ramp-Down Settlement Amount (RDSA) Future market *settlement amount* will not include CMSC and will account for the day-ahead market impact.	3.7.16
Hourly Uplift (HUSA) – Ramp-Down Settlement Amount component *Market rules* reference: Chapter 9, Section 3.9	Real-Time Ramp-Down Settlement Amount Uplift (RDSAU)	3.7.16

Table **3-4** lists all current market *settlement amounts* applicable to congestion management *settlement* credit (CMSC). These *settlement amounts* will not be required in the future market with the introduction of a day-ahead market and single schedule market, and will be retired upon implementation of MRP.

Table 3-4: Retired CMSC Current Market Settlement Amounts

Current Market Settlement Amount
Congestion Management Settlement Credit for Energy (CMSC) *Market rules* reference: Chapter 9, Section 3.5
Hourly Uplift (HUSA) – Congestion Management Settlement Credit component *Market rules* reference: Chapter 9, Section 3.9
Hourly Uplift (HUSA) – Ramp-Down Settlement Amount component *Market rules* reference: Chapter 9, Section 3.9
Ramp-Down CMSC Claw Back *Market rules* reference: Chapter 9, Section 3.5.1G
Self-Induced Dispatchable Load CMSC Clawback *Market rules* reference: Chapter 9, Section 3.5.1A
SEAL Congestion Management Settlement Credit Amount *Market rules* reference: Not applicable

Table 3-5 lists all current market *settlement amounts* applicable to the DACP. These *settlement amounts* will not be required in the future market and will be retired upon implementation of MRP. With the introduction of a day-ahead market, these *settlement amounts* will be replaced by DAM financially binding schedules and settled under the two-*settlement* system.

The DA-PCG *settlement amounts* under DACP have been included in Table 3-3. These *settlement amounts* will be replaced by the DAM_GOG and DAM Make-Whole Payment Uplift (DAM_MWPU).

Table 3-5: Retired DACP Current Market Settlement Amounts

Current Market Settlement Amount
Day-Ahead Generator Withdrawal Charge (DA_GWC) *Market rules* reference: Chapter 9, Section 3.8F
Day-Ahead Generator Withdrawal Rebate *Market rules* reference: Chapter 9, Section 4.8.2.14
Intertie Offer Guarantee (IOG) – Day-Ahead component *Market rules* reference: Chapter 9, Section 3.8A.2A
Day-Ahead Import Failure Charge (DA_IFC) *Market rules* reference: Chapter 9, Section 3.8B
Hourly Uplift (HUSA) – Day-Ahead Import Failure Charge component *Market rules* reference: Chapter 9, Section 3.9
Day-Ahead Export Failure Charge (DA_EFC) *Market rules* reference: Chapter 9, Section 3.8D

Current Market Settlement Amount
Hourly Uplift (HUSA) – Day-Ahead Export Failure Charge component *Market rules* reference: Chapter 9, Section 3.9
Day-Ahead Linked Wheel Failure Charge *Market rules* reference: Chapter 9, Section 3.8E
Hourly Uplift (HUSA) – Day-Ahead Linked Wheel Failure Charge component *Market rules* reference: Chapter 9, Section 3.9
Day-Ahead Fuel Cost Compensation Credit (DA_FCC) *Market rules* reference: Chapter 9, Section 4.7E
Day-Ahead Fuel Cost Compensation Debit (DA_FCCU) *Market rules* reference: Chapter 9, Section 4.8.1.12

Table 3-6 lists all current market *settlement amounts* to settle the *transmission rights (TR) market*. With the introduction of LMPs and a day-ahead market, conforming changes will be required for the financial *TR market*. The *IESO* will incorporate LMPs and move *TR market settlements* from real-time to day-ahead. Under a separate initiative from MRP, the *IESO* is undertaking a review of Ontario's *TR market*. Upon completion of the TR Market Review, *settlement amounts* will be determined for the future market. The TR Market Review will also address where and how the real-time *intertie* congestion will be collected and settled.

Table 3-6: Replaced Current Transmission Rights Market Settlement Amounts

Current Market Settlement Amount	Future Market Settlement Amount	Section Reference
Transmission Rights Auction Settlement Debit (TRAD) *Market rules* reference: Chapter 8, Section 4.17	TR Market Review to Inform	3.7.15
TR Clearing Account Credit (TRCAC) *Market rules* reference: Chapter 8, Section 4.7.2		3.7.15
Transmission Charge Reduction Fund (TCRF) *Market rules* reference: Chapter 9, Section 3.6.2		3.7.15
Transmission Rights Settlement Credit (TRSC) *Market rules* reference: Chapter 9, Section 3.6.1		3.7.15
TR Market Shortfall Debit *Market rules* reference: Chapter 9, Section 6.14.5.2		3.7.15

3.5 Collection of Settlement-Ready Data

3.5.1 The Business Requirements of Settlement-Ready Data Processing

As noted in the Figure 2-2 context diagram, the *settlement process* will require data inputs from all existing sources. In addition to the existing flows, several new or modified information flows will be required to support the *settlement process*. This section will enumerate each of the data elements arriving at the *settlement process* via these new or modified information flows in a state of readiness equivalent to current practices in the DACP and the *real-time market*.

The notion of *settlement*-ready data in the context of the current *real-time market* is a significant factor in determining the boundary of the *settlement process* itself. In the future market the *settlement process* will be based on the premise that all data provided to it from the DAM, pre-dispatch (PD) or real-time (RT) calculation engines or the Facility Registration process, will have undergone efforts to consider accuracy and completeness and their own validations before being passed to the *settlement process*. The *settlement process* will continue to perform its own data validations as it receives data from other sources and systems.

Similar to the current market, *settlement*-ready data will continue to reflect the following state of readiness:

- All *settlement* data is made ready to form the basis of a *settlement* calculation before the first (preliminary) attempt is made to conduct such a calculation;
- The *settlement process* itself is the recipient of *settlement*-ready data. Therefore, no further modification to the data is made between the point at which the data is collected by the *settlement process* and the preliminary calculation is made; and
- Prior to being provided to the *settlement process*, data has already been subject to various upstream quality-control processes within the *IESO*, resulting in *settlement*-ready data. The most prominent example currently in use in today's *real-time market* is the *metering data* Validation, Estimation and Editing (VEE) process.

The *market participant* receiving *settlement*-ready data and *settlement* calculations is also given an opportunity to review the data used and raise any apparent disagreements with the *IESO* after the preliminary *settlement* calculations are performed.

3.5.1.1 Nomenclature for all Settlement Data

The following information provides an example of nomenclature for *settlement* data, which is described in upcoming sections. This nomenclature reflects the level of information pertaining to each *settlement* variable that will need to be received by the *settlement process* in order to adequately perform the necessary *settlement* calculations.

Table 3-7: Nomenclature of Settlement Variables

Timeframe	***Variable Name***	**'r', 'k', 'h', 'm', 'i', 't', 'v', 'p', 'pdr'**
Designates the data that is received from the calculation engine for the specific timeframe.	The identifier of the specific data series to which the variable pertains.	SPECIFIC IDENTIFIERS WHERE APPLICABLE: 'r' – specific class 'r' *operating reserve* 'k' – *market participant* 'h' - *settlement hour* 'm' – *delivery point* 'i' - *intertie metering point* 't' – *metering interval* 'v' – virtual transaction zonal trading entity 'p' – *pseudo-unit* 'pdr' – pre-dispatch run

Variable Example:

$\boldsymbol{DAM\_QSI_{k,h}^{m}}$

Expanded Description:

Day-ahead market quantity of *energy* scheduled for injection by *market participant* 'k' at *delivery point* 'm' of *settlement hour* 'h'.

3.5.2 Collection of Registration Data

The *settlement process* requires data from the Authorization and Participation and Facility Registration processes in order to carry out its various functions.

Registration data will be considered to be static and will be applicable to a minimum time resolution of one calendar day. Any changes to the sub-classification of a *facility* will be applied uniformly over all hours in a given *trading day*. The registration data required in order to facilitate the *settlement process* is further described in the following sub-sections. For more information regarding registration data, refer to the Authorization and Participation and the Facility Registration detailed design documents.

3.5.2.1 Market Participant Associations – Physical Transactions

Similar to the current *real-time market* practice, every *delivery point* within Ontario will continue to be associated with a single, authorized *metered market participant* (MMP). Any physical transaction *settlement amounts* associated with such *delivery points* will be allocated to the *metered market participant* for that *delivery point.* Therefore, any authorizations for *market participants* to conduct physical transactions for *delivery points* within Ontario will be reflected in the current information flow from the Registered Revenue Meter Installation process into the *settlement process*. The *settlement process* will continue to use the organizational roles and responsibilities, physical *facility* resource identifiers, and *market participant* resource relationships identified in Section 3.4 of the Facility Registration detailed design document.

In the case of physical transactions at the *interties*, the *settlement process* will continue to associate *settlement amounts* with the *market participant* to whom the transaction quantity is assigned by the day-ahead (DAM), pre-dispatch (PD) and real-time (RTM) calculation engines.

3.5.2.2 Market Participant Associations – Virtual Transactions

The ability to conduct virtual transactions will be assigned to *market participants* through the Facility Registration and Authorization and Participation processes. *Dispatch data* for virtual transaction *offers* or *bids* for *energy* will be processed in the day-ahead market. *Dispatch data* for virtual transactions to supply *operating reserve* will not be permitted in the future day-ahead or *real-time market.* The submission of any virtual *offers* and *bids* for *energy* will be validated against established criteria. Refer to the Prudential Security detailed design document for more information about the daily screening of virtual transactions and the conditions under which the virtual transaction *offers* or *bids* for *energy* will be rejected.

3.5.2.3 Market Participant Associations – Registered Facilities

As part of MRP, in order to achieve consistent *settlement* treatment, there may be different calculations for different types of *facilities*. These *facility* types go beyond the various designations given to *facilities* in the current *real-time market*. In order to apply the correct *settlement* calculations to each relevant type of *facility*, it will be necessary for the *settlement process* to receive the appropriate *facility* sub-classifications for every *facility*. As described earlier, these sub-classifications must be constant for every *facility* over the course of all hours in the same *trading day*. They will also be added to any classifications given to *delivery points* for the purposes of settling the *real-time market*.

Designations pertaining to virtual transactions will be inherent in the data received from the day-ahead (DAM) calculation engine. Designations pertaining to physical transactions will be inherent in the data received from the DAM, PD and RT calculation engines.

The *settlement process* will continue to use the organization roles and responsibilities, physical *facility* resource identifiers, and *market participant* resource relationships identified in Section 3.4: General Requirements for Facility Registration of the Facility Registration detailed design document.

3.5.2.4 Market Price Associations

With the implementation of MRP, the *IESO* will utilize zonal and nodal prices. The *settlement process* will require the appropriate virtual zonal energy prices at the virtual transaction zonal trading entity and the appropriate nodal prices at each *delivery point* in order to apply the correct price to all *settlement* calculations.

All registered *generation facilities*, *dispatchable loads* and price responsive loads will be subject to the applicable nodal price at the *delivery point*. *Non-dispatchable loads* will be subject to the Ontario zonal price, adjusted for the province-wide allocation of the cost of forecast deviation. Lastly authorized DAM *market participants* conducting virtual transactions will be subject to the applicable virtual zonal *energy* price at the virtual zonal trading entity.

3.5.2.5 Facility Registration Parameters

The *settlement process* required for the future day-ahead market and *real-time market* will use a number of facility registration parameters. Table 3-8 identifies the static facility registration parameter data that will be used by the *settlement process* in the calculation of generator offer guarantee payments.

Table 3-8: Facility Registration Data Used for Settlement

Name	Description
Elapsed Time to Dispatch	**Applicable to NQS *generation units.*** Minimum amount of time, in minutes, between the time at which a start-up sequence is initiated for a *generation unit* and the time at which it becomes dispatchable by reaching its *minimum loading point.* **Unit of measurement:** minutes
Start Indication Value	**Applicable to hydroelectric *generation facilities.*** Minimum amount of *energy* a resource must be scheduled to determine whether the *generation units* associated with resource have used up one or more of their *maximum number of starts per day*. **Unit of measurement:** MW

3.5.3 Collection of Dispatch Data from Market Participants

In the future *energy* and *operating reserve market*, the day-ahead (DAM), pre-dispatch (PD) and real-time (RT) calculation engines will use the *dispatch data* submitted from *market participants.* The new hourly and daily *dispatch data* construct will provide the financial and non-financial *dispatch data* parameters that are submitted by *market participants* on a daily basis.

Table 3-9 provides a listing of the non-financial *dispatch data* parameters that will be required by the *settlement process.*

Table 3-9: Non-Financial Hourly and Daily Dispatch Data Used for Settlement

Parameter Name (Type)	Description
Hourly Must Run (Hourly)	Minimum amount of *energy*, in MWh, that a *generation unit* associated with a dispatchable hydroelectric *generation facility* must produce in any one hour to prevent the *registered facility* from operating in a manner that would endanger the safety of any person, damage equipment, or violate any *applicable law*. **Unit of measurement:** MWh
Minimum Hourly Output (Hourly)	Minimum amount of *energy*, in MWh, that a *generation unit* associated with a dispatchable hydroelectric *generation facility* must, if economic, produce in any one hour to prevent the *registered facility* from operating in a manner that would endanger the safety of any person, damage equipment, or violate any *applicable law.* **Unit of measurement:** MWh
Minimum Daily Energy Limit (Daily)	Minimum amount of *energy*, in MWh, that a *generation unit* associated with a dispatchable hydroelectric *generation facility* must be scheduled to supply *energy* within a *dispatch day* to prevent the *registered facility* from operating in a manner that would endanger the safety of any person, damage equipment or violate any *applicable law*. **Unit of measurement:** MWh

Parameter Name (Type)	Description
Maximum Number of Start per Day (Daily)	Maximum number of times a *generation unit* can be started within a *dispatch day*. **Unit of measurement:** number
Forbidden Regions (Daily)	One or more operating regions (upper limit and lower limit), in MW, within which a hydroelectric *generation unit* cannot maintain steady state operation without causing equipment damage. DAM schedules which are at or within the boundary of a *forbidden region* will be adjusted prior to calculating the DAM make-whole payments. **Unit of measurement:** MW
Minimum Loading Point (Daily)	Minimum MW output that a *generation unit* must maintain to remain stable without the support of ignition. MLP_k^m of *delivery point* ‘m’ for *market participant* ‘k’ MLP_k^c of combustion turbine *delivery point* ‘c’ for *market participant* ‘k’ MLP_k^s of steam turbine *delivery point* ‘s’ for *market participant* ‘k’ MLP_k^p of *pseudo-unit* ‘p’ for *market participant* ‘k’. **Unit of measurement:** MW
Minimum Generation Block Run-Time (Daily)	Minimum number of consecutive hours a *generation unit* must be scheduled to its *minimum loading point.* **Unit of measurement:** hours
Minimum Generation Block Down-Time (Daily)	Minimum number of hours between the time a *generation unit* was last at its *minimum loading point* before de-synchronization, and the time the *generation unit* can be scheduled back to its MLP after re-synchronizing. **Unit of measurement:** hours
Ramp Up Energy to MLP (ramp hours to MLP; and energy per ramp hour) (Daily)	*Energy*, in MWh, a *generation unit* is expected to produce from the time of synchronization to the time it reaches its *minimum loading point.* **Unit of measurement:** MWh
Single Cycle Mode (Daily)	Mode of operating a combined cycle *generation facility’s* combustion turbine *generation unit* without the associated steam turbine *generation unit(s).* **Unit of measurement:** Y(Yes)/N(No)
Linked Resources, Time Lag, MWh (Daily)	Links the *energy offers* between two or more resources on the same hydroelectric cascade river system with a time lag indicator of amount of time it takes for water to be discharged from an upstream resource to a linked downstream resource. A time lag of zero indicates that there is no delay between the schedules for the linked resources. A time lag greater than zero indicates that the linked resources are scheduled with a delay between them. **Unit of measurement:** hours, MWh

Financial *dispatch data* parameters comprising *offer* and *bid* data submitted for physical transactions and virtual transactions and utilized by the *settlement process* are defined for the day-ahead market, pre-dispatch and *real-time market* in the following sub-sections respectively under the caption Offer and Bid Data.

3.5.4 Collection of Day-Ahead Market Data

3.5.4.1 DAM Calculation Engine

The DAM calculation engine will provide new inputs into the *settlement process*. It is important to note that the DAM calculation engine will use both *dispatch data* submitted in the day-ahead market and the associated registration data. However, the *settlement process* will not receive these data elements directly from the DAM calculation engine, but rather from the source system or database. This is consistent with the practice in the current *real-time market*. This also avoids the possibility that any intermediate modifications made to DAM *bid* or *offer* data within the DAM calculation engine for optimization purposes to be accidentally submitted to the *settlement process*.

Data received from the DAM calculation engine will be classified into a series of *settlement* variables that are used extensively in this document to describe the various calculations performed by the *settlement process*.

The tables that follow in this section describe the *settlement* variables that will be received by the *settlement process* from the DAM calculation engine, grouping the variables into the following categories:

1. Prices;
2. Schedules;
3. Mitigation results;
4. DAM unit commitment events; and
5. Other.

Where applicable, the *settlement* variables listed in these tables will be used throughout this document in the description of various DAM *settlement* calculations.

The variables described in these tables are new and will be calculated by the DAM calculation engine on a daily basis, and will then pass through any subsequent verification and quality control processes, resulting in *settlement*-ready data. These tasks must be performed in time to provide all relevant data to the first *settlement* stage of the two-*settlement* system.

Table 3-10 lists the prices received from the DAM calculation engine.

Table 3-10: Prices Received from the DAM Calculation Engine

Variable	Name	Description
$DAM\_LMP_h^z$	DAM Zonal Locational Marginal Price of Energy	Day-ahead *energy market price* at zone ‘z’ in *settlement hour* ‘h’. Where: z = Ontario zone **Unit of measurement:** $/MWh to the nearest cent **Time resolution:** hourly
$DAM\_LMP_h^m$	DAM Locational Marginal Price of Energy at a Delivery Point	Day-ahead *energy market price* at *delivery point* ‘m’ in *settlement hour* ‘h’. **Unit of measurement:** $/MWh to the nearest cent **Time resolution:** hourly

Variable	Name	Description
$DAM\_LMP_{h}^{i}$	DAM Locational Marginal Price of Energy at an Intertie Metering Point	Day-ahead *energy market price* at *intertie metering point* 'i' in *settlement hour* 'h'. **Unit of measurement:** $/MWh to the nearest cent **Time resolution:** hourly
$DAM\_LMP_{h}^{v}$	DAM Locational Marginal Price of Energy at a Virtual Transaction Zonal Trading Entity	Day-ahead *energy market price* at virtual transaction zonal trading entity 'v' in *settlement hour* 'h'. **Unit of measurement:** $/MWh to the nearest cent **Time resolution:** hourly
$DAM\_LMP_{h}^{c}$	DAM Locational Marginal Price of Energy at a Combustion Turbine	Day-ahead *energy market price* at combustion turbine *delivery point* 'c' in *settlement hour* 'h'. **Unit of measurement:** $/MWh to the nearest cent **Time resolution**: hourly
$DAM\_LMP_{h}^{s}$	DAM Locational Marginal Price of Energy at a Steam Turbine	Day-ahead *energy market price* at steam turbine *delivery point* 's' in *settlement hour* 'h'. **Unit of measurement:** $/MWh to the nearest cent **Time resolution**: hourly
$DAM\_PROR_{r,h}^{m}$	DAM Locational Marginal Price of Operating Reserve at a Delivery Point	Day-ahead *market price* of *class r reserve* at *delivery point* 'm' in *settlement hour* 'h'. Where: r1 = 10-minute spinning *operating reserve* r2 = 10-minute non-spinning *operating reserve* r3 = 30-minute *operating reserve* **Unit of measurement:** $/MWh to the nearest cent **Time resolution:** hourly
$DAM\_PROR_{r,h}^{i}$	DAM Locational Marginal Price of Operating Reserve at an Intertie Metering Point	Day-ahead *market price* of *class r reserve* at *intertie metering point* 'i' in *settlement hour* 'h'. Where: r1 = not applicable r2 = 10-minute non-spinning *operating reserve* r3 = 30-minute *operating reserve* **Unit of measurement:** $/MWh to the nearest cent **Time resolution:** hourly
$DAM\_PROR_{r,h}^{c}$	DAM Locational Marginal Price of Operating Reserve at a Combustion Turbine	Day-ahead *market price* of *class r reserve* at combustion turbine *delivery point* 'c' in *settlement hour* 'h'. Where: r1 = 10-minute spinning *operating reserve* r2 = 10-minute non-spinning *operating reserve* r3 = 30-minute *operating reserve* **Unit of measurement:** $/MWh to the nearest cent **Time resolution:** hourly

Variable	Name	Description
$DAM\_PROR^{s}_{r,h}$	DAM Locational Marginal Price of Operating Reserve at a Steam Turbine	Day-ahead *market price* of *class r reserve* at steam turbine *delivery point* ‘s’ in *settlement hour* ‘h’. Where: r1 = 10-minute spinning *operating reserve* r2 = 10-minute non-spinning *operating reserve* r3 = 30-minute *operating reserve* **Unit of measurement:** $/MWh to the nearest cent **Time resolution:** hourly
$DAM\_ICP^{i}_{h}$	DAM Intertie Congestion Price	DAM *ICP* for *energy* at *intertie metering point* ‘i’ in *settlement hour* ‘h’. **Unit of measurement:** $/MWh to the nearest cent **Time resolution:** hourly

Table 3-11 lists the schedules received from the DAM calculation engine.

Table 3-11: Schedules Received from the DAM Calculation Engine

Variable	Name	Description
$DAM\_QSI^{m}_{k,h}$	DAM Quantity of Energy Scheduled for Injection at a Delivery Point	DAM quantity of *energy* scheduled for injection by *market participant* ‘k’ at *delivery point* ‘m’ in *settlement hour* ‘h’. **Unit of measurement:** MWh **Time resolution:** hourly
$DAM\_QSI^{i}_{k,h}$	DAM Quantity of Energy Scheduled for Injection at an Intertie Metering Point	DAM quantity of *energy* scheduled for injection by *market participant* ‘k’ at *intertie metering point* ‘i’ in *settlement hour* ‘h’. **Unit of measurement:** MWh **Time resolution:** hourly
$DAM\_QSI^{p}_{k,h}$	DAM Quantity of Energy Scheduled for Injection at a Pseudo-Unit	DAM quantity of *energy* scheduled for injection by *market participant* ‘k’ at *pseudo-unit* ‘p’ in *settlement hour* ‘h’. **Unit of measurement:** MWh **Time resolution**: hourly
$DAM\_QSI^{c}_{k,h}$	DAM Quantity of Energy Scheduled for Injection at a Combustion Turbine	DAM quantity of *energy* scheduled for injection by *market participant* ‘k’ at combustion turbine *delivery point* ‘c’ in *settlement hour* ‘h’. **Unit of measurement:** MWh **Time resolution**: hourly
$DAM\_QSI^{s}_{k,h}$	DAM Quantity of Energy Scheduled for Injection at a Steam Turbine	DAM quantity of *energy* scheduled for injection by *market participant* ‘k’ at steam turbine *delivery point* ‘s’ in *settlement hour* ‘h’. **Unit of measurement:** MWh **Time resolution**: hourly

Variable	Name	Description
$DAM\_QVSI^{v}_{k,h}$	DAM Virtual Quantity of Energy Scheduled for Injection at a Virtual Transaction Zonal Trading Entity	DAM virtual quantity of *energy* scheduled for injection by *market participant* 'k' at virtual transaction zonal trading entity 'v' in *settlement hour* 'h'. **Unit of measurement:** MWh **Time resolution:** hourly
$DAM\_QSW^{m}_{k,h}$	DAM Quantity of Energy Scheduled for Withdrawal at a Delivery Point	DAM quantity of *energy* scheduled for withdrawal by *market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' including the DAM schedules for all *non-dispatchable loads* at *delivery point* 'm'. **Unit of measurement:** MWh **Time resolution:** hourly
$DAM\_QSW^{i}_{k,h}$	DAM Quantity of Energy Scheduled for Withdrawal at an Intertie Metering Point	DAM quantity of *energy* scheduled for withdrawal by *market participant* 'k' at *intertie metering point* 'i' in *settlement hour* 'h'. **Unit of measurement:** MWh **Time resolution:** hourly
$DAM\_QVSW^{v}_{k,h}$	DAM Virtual Quantity of Energy Scheduled for Withdrawal at a Virtual Transaction Zonal Trading Entity	DAM virtual quantity of *energy* scheduled for withdrawal by *market participant* 'k' at virtual transaction zonal trading entity 'v' in *settlement hour* 'h'. **Unit of measurement:** MWh **Time resolution:** hourly
$DAM\_QSOR^{m}_{r,k,h}$	DAM Scheduled Quantity of Operating Reserve at a Delivery Point	DAM scheduled quantity of *class r reserve* for *market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h'. Where: r1 = 10-minute spinning *operating reserve* r2 = 10-minute non-spinning *operating reserve* r3 = 30-minute *operating reserve* **Unit of measurement:** MWh **Time resolution:** hourly
$DAM\_QSOR^{i}_{r,k,h}$	DAM Scheduled Quantity of Operating Reserve at an Intertie Metering Point	DAM scheduled quantity of *class r reserve* for *market participant* 'k' at *intertie metering point* 'i' in *settlement hour* 'h'. Where: r1 = not applicable r2 = 10-minute non-spinning *operating reserve* r3 = 30-minute *operating reserve* **Unit of measurement:** MWh **Time resolution:** hourly

Variable	Name	Description
$DAM\_QSOR^{c}_{r,k,h}$	DAM Scheduled Quantity of Operating Reserve at a Combustion Turbine	DAM scheduled quantity of *class r reserve* for *market participant* 'k' at combustion turbine *delivery point* 'c' in *settlement hour* 'h'. Where: r1 = 10-minute spinning *operating reserve* r2 = 10-minute non-spinning *operating reserve* r3 = 30-minute *operating reserve* **Unit of measurement:** MWh **Time resolution:** hourly
$DAM\_QSOR^{s}_{r,k,h}$	DAM Scheduled Quantity of Operating Reserve at a Steam Turbine	DAM scheduled quantity of *class r reserve* for *market participant* 'k' at steam turbine *delivery point* 's' in *settlement hour* 'h'. Where: r1 = 10-minute spinning *operating reserve* r2 = 10-minute non-spinning *operating reserve* r3 = 30-minute *operating reserve* **Unit of measurement:** MWh **Time resolution:** hourly

The DAM calculation engine will perform ex-ante mitigation for economic withholding and produce conduct and price impact test results and mitigated *dispatch data* when such tests result in failure. See the Market Power Mitigation detailed design document for a description of these processes. The DAM calculation engine will be the source of mitigated *dispatch data* and test results provided to the *settlement process* for potential *settlement* mitigation of make-whole payments and other guarantee payments.

Table 3-12 identifies the mitigation data provided by the DAM calculation engine to the *settlement process* at a summary level.

Table 3-12: Mitigation Results from the DAM Calculation Engine

Name	Description
Conduct Test Results	Pass or fail results of units at *delivery point* 'm' undergoing the conduct test for each *dispatch hour* 'h' of the next *dispatch day*.
Price Impact Test Results	Pass or fail results of units at *delivery point* 'm' undergoing the price impact test for each *dispatch hour* 'h' of the next *dispatch day*.

Name	Description
Mitigated Dispatch Data	Mitigated *dispatch data* enhanced to reflect the most restrictive failed *dispatch data* parameter during the hour or commitment period for the unit that failed the conduct test for *market participant* 'k' at *delivery point* 'm' during *settlement hour* 'h' of the next *dispatch day*. Potential mitigated financial *dispatch data* parameters include: • *Energy offers* • Start-up offers • Speed no-load offers • *Operating reserve offers* • *Energy offers* for the range of production up to MLP
Resource Constrained Area Mitigation Test Condition	Constrained area mitigation condition for each resource at *delivery point* 'm' prevailing during each *settlement hour* 'h' of the next *dispatch day*. The relevant impact threshold used in make-whole payment impact testing for *market participant* 'k' will be applied depending on the constrained area condition under which the resource failed the conduct test. See Table 3-13: DAM Thresholds from the Market Power Mitigation Information System.

Table 3-13 identifies the DAM mitigation data provided by the Market Power Mitigation Information System to the *settlement process*.

Table 3-13: DAM Thresholds from the Market Power Mitigation Information System

Name	Description
Make-Whole Payment Impact Test Thresholds	The relevant impact threshold used in make-whole payment impact testing for *market participant* 'k' will be applied depending on the constrained area condition under which the resource failed the conduct test: • Broad constrained area (BCA) for *energy* • Narrow constrained area (NCA) for *energy* • Dynamic constrained area (DCA) for *energy* • Reliability constraint for *energy* • Global market power for *energy* • Global market power for *operating reserve* • Local market power for *operating reserve* Refer to the Market Power Mitigation detailed design, Table 3-3 for more information on mitigation conditions for make-whole payment impact testing.

Table 3-14 provides a listing of the data from the DAM calculation engine passes, prior to, and during, the *reliability* scheduling pass that will be used by the *settlement process* in the calculation of the DAM Reliability Scheduling Uplift (DRSU), discussed in Section 3.7.4.

Table 3-14: DAM Unit Commitment Events

Variable	Name	Description
$\text{PRE\_RSP\_DAM\_QSI}_{k,h}^{m}$	Latest DAM pass prior to the Reliability Scheduling Pass of DAM Quantity of Energy Scheduled for Injection at a Delivery Point	Represents the latest schedule from the DAM calculation engine passes prior to the *reliability* scheduling pass. DAM quantity of *energy* scheduled for injection by *market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' during the latest prior pass. **Unit of measurement:** MWh **Time resolution:** hourly
$\text{RSP\_DAM\_QSI}_{k,h}^{m}$	Reliability Scheduling Pass of DAM Quantity of Energy Scheduled for Injection at a Delivery Point	Represents the *reliability* scheduling pass that determines if the resources committed by prior passes are sufficient to meet the peak zonal forecast demand and commits additional NQS *generation facilities* if required. DAM quantity of *energy* scheduled for injection by *market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' during the *reliability* scheduling pass. **Unit of measurement:** MWh **Time resolution:** hourly
$\text{PRE\_RSP\_DAM\_QSI}_{k,h}^{i}$	Latest DAM pass prior to the Reliability Scheduling Pass of DAM Quantity of Energy Scheduled for Injection at a Intertie Metering Point	Represents the latest schedule from the DAM calculation engine passes prior to the *reliability* scheduling pass. DAM quantity of *energy* scheduled for injection by *market participant* 'k' at *intertie metering point* 'i' in *settlement hour* 'h' during the latest prior pass. **Unit of measurement:** MWh **Time resolution:** hourly
$\text{RSP\_DAM\_QSI}_{k,h}^{i}$	Reliability Scheduling Pass of DAM Quantity of Energy Scheduled for Injection at an Intertie Metering Point	Represents the *reliability* scheduling pass that determines if the resources committed by prior passes are sufficient to meet the peak zonal forecast demand and commits additional imports, if required. DAM quantity of energy scheduled for injection by *market participant* 'k' at *intertie metering point* 'i' in *settlement hour* 'h' during the *reliability* scheduling pass. **Unit of measurement:** MWh **Time resolution:** hourly

Variable	Name	Description
$PRE\_RSP\_DAM\_QSOR^{m}_{r,k,h}$	Latest DAM pass prior to the Reliability Scheduling Pass of DAM Scheduled Quantity of Operating Reserve at a Delivery Point	Represents the latest DAM pass prior to the *reliability* scheduling pass. Determines the initial set of commitments for NQS *generation facilities* required to satisfy the average zonal forecast *demand* for the next day. DAM scheduled quantity of *class r reserve* for *market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' during the prior passes. Where: r1 = 10-minute spinning *operating reserve* r2 = 10-minute non-spinning *operating reserve* r3 = 30-minute *operating reserve* **Unit of measurement:** MWh **Time resolution:** hourly
$RSP\_DAM\_QSOR^{m}_{r,k,h}$	Reliability Scheduling Pass DAM Scheduled Quantity of Operating Reserve at a Delivery Point	Represents the *reliability* scheduling pass that determines if the resources committed by prior passes are sufficient to meet the peak zonal forecast demand and commits additional NQS *generation facilities* if required. DAM scheduled quantity of class r reserve for *market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' during the *reliability* scheduling pass. Where: r1 = 10-minute spinning *operating reserve* r2 = 10-minute non-spinning *operating reserve* r3 = 30-minute *operating reserve* **Unit of measurement:** MWh **Time resolution:** hourly
$PRE\_RSP\_DAM\_QSOR^{i}_{r,k,h}$	Latest DAM pass prior to the Reliability Scheduling Pass of DAM Scheduled Quantity of Operating Reserve at an Intertie Metering Point	Represents the latest DAM pass prior to the *reliability* scheduling pass. Determines the initial set of commitments for imports required to satisfy the average zonal forecast *demand* for the next day. DAM scheduled quantity of *class r reserve* for *market participant* 'k' at *intertie metering point* 'i' in *settlement hour* 'h' during the prior passes. Where: r1 = not applicable

Variable	Name	Description
		r2 = 10-minute non-spinning *operating reserve* r3 = 30-minute *operating reserve* **Unit of measurement:** MWh **Time resolution:** hourly
$RSP\_DAM\_QSOR^{i}_{r,k,h}$	Reliability Scheduling Pass DAM Scheduled Quantity of Operating Reserve at an Intertie Metering Point	Determines if the resources committed by prior passes are sufficient to meet the peak zonal forecast demand and commits additional imports, if required. DAM scheduled quantity of class r reserve for *market participant* 'k' at *intertie metering point* 'i' in *settlement hour* 'h' during the *reliability* scheduling pass. Where: r1 = not applicable r2 = 10-minute non-spinning *operating reserve* r3 = 30-minute *operating reserve* **Unit of measurement:** MWh **Time resolution:** hourly
$PRE\_RSP\_Import\_DAM\_MWP^{i}_{k,h}$	Import DAM Make-Whole Payment Prior to the Reliability Scheduling Pass	Represents the DAM_MWP made to imports that are scheduled in the pass prior to the *reliability* scheduling pass of the DAM calculation engine. For the *market participant*/resource/*trading day*/trading hour, if there is a schedule in the mitigated scheduling pass, then the schedule from the mitigated scheduling pass will be used, otherwise the schedule from the as-offered scheduling pass will be used. DAM_MWP by *market participant* 'k' at *intertie metering point* 'i' in *settlement hour* 'h' **Unit of measurement:** MWh **Time resolution:** hourly
$RSP\_Import\_DAM\_MWP^{i}_{k,h}$	Import DAM Make-Whole Payment from the Reliability Scheduling Pass	Represents the DAM_MWP made to imports that are incrementally or newly scheduled in the *reliability* scheduling pass of the DAM calculation engine. DAM_MWP by *market participant* 'k' at *intertie metering point* 'i' in *settlement hour* 'h'. **Unit of measurement:** MWh **Time resolution:** hourly
$RSP\_New\_NQS\_DAM\_GOG^{m}_{k,h}$	DAM Generator Offer Guarantee from the	Represents the DAM_GOG payments generated by the final pass of the DAM

Variable	Name	Description
	Reliability Scheduling Pass	calculation engine that are made to NQS *generation facilities* that are first committed in the *reliability* scheduling pass for a contiguous set of hours. In order to be first committed in the *reliability* scheduling pass, the schedules in preceding passes must be zero. DAM_GOG by *market participant* ‘k’ at *delivery point* ‘m’ in *settlement hour* ‘h’ **Unit of measurement:** MWh **Time resolution:** DAM commitment period

3.5.4.2 DAM Offer and Bid Data

Authorized DAM *market participants* will be able to submit *offers* and *bids* for virtual transactions and physical transactions, depending on their authorized trading privileges and the types of *facilities* they operate. Except for the *offers* and *bids* that have been substituted with reference levels due to ex-ante market power mitigation, all DAM *offers* and *bids* will be used by the *settlement process* in the form that they were originally submitted by the *market participant*. If mitigated, the *settlement process* will use the mitigated *offer* or *bid*.

Within this section, the complete set of *offer* and *bid* data for *energy* transactions in the day-ahead market is described in terms of:

- *offers* and *bids* for physical transactions; and
- *offers* and *bids* for virtual transactions.

3.5.4.3 Offers and Bids for Physical Transactions

Offers may be submitted for all physical transactions involving *energy* for the following types of *facilities* and transactions:

- Dispatchable *generation facilities*;
- Non-dispatchable *generation facilities*; and
- Import transactions.

Bids may be submitted for all physical transactions involving *energy* for the following types of *facilities* and transactions:

- *Dispatchable loads*;
- *Hourly demand response* resources;
- Price responsive loads; and
- Export transactions.

DAM *offers* and *bids* will be specific to a generation or load resource and associated *delivery point* or to an import/export transaction specific to a *boundary entity* source/sink assigned to a *market participant* at an *intertie metering point*. Table 3-15 summarizes the attributes of these *offers* and *bids*.

Market participants will not submit *bids* for *energy* into the day-ahead market or the *real-time market* for *non-dispatchable loads*. As is the case in the current *real-time market*, the *IESO* will represent *non-dispatchable loads* as part of the hourly average NDL *demand* forecasts to be used by the DAM calculation engine and the PD calculation engine.

Table 3-15: Financial Dispatch Data for Physical Transactions Submitted to the DAM

Variable	Name	Description
$DAM\_BE^{m}_{k,h}$	DAM Energy Offer at a Delivery Point	**Available to *generation facilities*.** A matrix of up to 20 *price-quantity pairs* offered by *market participant* 'k' to supply *energy* during *settlement hour* 'h'. *Energy offers* submitted in day-ahead, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *delivery point* 'm' of *settlement hour* 'h', arranged in ascending order by the offered price in each *price-quantity pair*, where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2.
$DAM\_BE^{i}_{k,h}$	DAM Energy Offer at an Intertie Metering Point	**Available to import transactions.** A matrix of up to 20 *price-quantity pairs* offered by *market participant* 'k' to supply *energy* during *settlement hour* 'h'. *Energy offers* submitted in day-ahead, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *intertie metering point* 'i' of *settlement hour* 'h', arranged in ascending order by the offered price in each *price-quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2.
$DAM\_BE^{p}_{k,h}$	DAM Energy Offer at a Pseudo-Unit	**Available to *generation facilities* associated with a *pseudo-unit.*** A matrix of up to 20 *price-quantity pairs* offered by *market participant* 'k' to supply *energy* during *settlement hour* 'h'. *Energy offers* submitted in day-ahead, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *pseudo-unit* 'p' of *settlement hour* 'h', arranged in ascending order by the offered price in each *price-quantity pair*, where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2.
$DAM\_BE^{c}_{k,h}$	DAM Energy Offer at a Combustion Turbine	**Available to *generation facilities* associated with a *pseudo-unit*.** A matrix of up to 20 *price-quantity pairs* offered by *market participant* 'k' to supply *energy* during *settlement hour* 'h'. *Energy offers* submitted in day-ahead, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at combustion turbine *delivery point* 'c' of *settlement hour* 'h', arranged in ascending order by the offered price in each *price-quantity pair*, where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2.
$DAM\_BE^{s}_{k,h}$	DAM Energy Offer at a Steam Turbine	**Available to *generation facilities* associated with a *pseudo-unit.*** A matrix of up to 20 *price-quantity pairs offered* by *market participant* 'k' to supply *energy* during *settlement hour* 'h'. *Energy offers* submitted in day-ahead, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at steam turbine *delivery point* 's' of *settlement hour* 'h', arranged in ascending order by the offered price in each *price-quantity pair*, where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2.

Variable	Name	Description
$DAM\_BE\_SU^{m}_{k,h}$	DAM Start-Up Offer	**Available to eligible *generation facilities*.** DAM start-up offer associated with financial *offers* for the first *settlement hour* 'h' of the DAM commitment period at *delivery point* 'm' for *market participant* 'k' *per-start.* **Unit of measurement:** $ (dollar rounded to the nearest cent *per-start*)
$DAM\_BE\_SU^{p}_{k,h}$	DAM Start-Up Offer for a Pseudo-Unit	**Available to eligible *generation facilities* associated with a *pseudo-unit.*** DAM start-up offer associated with financial *offers*, or when applicable, the start-up reference level for the first *settlement hour* 'h' of the DAM commitment period at *pseudo-unit* 'p' for *market participant* 'k' *per-start.* This is associated with the first hour of the DAM commitment period from which the PD commitment is advanced. **Unit of measurement:** $ (dollar rounded to the nearest cent *per-start*)
$DAM\_BE\_SU^{m}_{k,f}$	DAM Start-Up Offer for a Delivery Point Failure	**Available to eligible *generation facilities.*** DAM start-up offer associated with financial *offers*, subject to mitigation, at *delivery point* 'm' for *market participant* 'k' committed by the DAM calculation engine for the DAM commitment that bridges with the PD commitment that has a failure 'f'. **Unit of measurement:** $ (dollar rounded to the nearest cent *per start*)
$DAM\_BE\_SU^{p}_{k,f}$	DAM Start-Up Offer for a Pseudo-Unit with a Combustion Turbine Failure	**Available to eligible *generation facilities* associated with a *pseudo-unit.*** Start-up offer associated with financial *offers* at *pseudo-unit* 'p' for *market participant* 'k' that was offered into the day-ahead market for the DAM financially binding schedule that bridges with the PD commitment that the CT failure 'f' occurred in. **Unit of measurement:** $ (dollar rounded to the nearest cent *per start*)
$DAM\_BE\_SNL^{m}_{k,h}$	DAM Speed No-load Offer	**Available to eligible *generation facilities*.** DAM speed no-load offer associated with financial *offers* for a given *settlement hour* 'h' at *delivery point* 'm' for *market participant* 'k' which may be subject to pro rata reduction based on $N^{m}_{k,h}$. Where $N^{m}_{k,h}$ is the number of 5-minute intervals that that *delivery point* 'm' for *market participant* 'k' was injecting *energy* within the *settlement hour* 'h'. **Unit of measurement:** $ (dollar rounded to the nearest cent *per-start*)
$DAM\_BE\_SNL^{p}_{k,h}$	DAM Speed no-load Offer for a Pseudo-Unit	**Available to eligible *generation facilities* associated with a *pseudo-unit.*** DAM speed no-load offer, or when applicable, the speed no-load reference level for a given *settlement hour* 'h' for *market participant* 'k' at *pseudo-unit* 'p'. **Unit of measurement:** $ (dollar rounded to nearest cent *per-start*)
$DAM\_BL^{m}_{k,h}$	DAM Energy Bid Submitted at a Delivery Point	**Available to dispatchable loads and price responsive loads.** A matrix of up to 20 *price-quantity pairs bid* by *market participant* 'k' to withdraw *energy* during *settlement hour* 'h'. *Energy bids* submitted in day-ahead, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *delivery point* 'm' of *settlement hour* 'h', arranged in ascending order by the offered price in each *price-quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2.

Variable	Name	Description
$DAM\_BL^{i}_{k,h}$	DAM Energy Bid Submitted at an Intertie Metering Point	**Available to export transactions.** A matrix of up to 20 *price-quantity pairs bid* by *market participant* 'k' to withdraw *energy* during *settlement hour* 'h'. *Energy bids* submitted in day-ahead, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *intertie metering point* 'i' of *settlement hour* 'h', arranged in ascending order by the offered price in each *price-quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2.
$DAM\_BOR^{m}_{r,k,h}$	DAM Operating Reserve Offer Submitted at a Delivery Point	**Available to eligible dispatchable *registered facilities*.** A matrix of up to 5 *price-quantity pairs* offered by *market participant* 'k' to supply *class r reserve* during *settlement hour* 'h'. *Operating reserve offer* submitted in day-ahead, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *delivery point* 'm' of *settlement hour* 'h', arranged in ascending order by the offered price in each *price-quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2. Where: r1 = 10-minute spinning *operating reserve* r2 = 10-minute non-spinning *operating reserve* r3 = 30-minute *operating reserve*
$DAM\_BOR^{i}_{r,k,h}$	DAM Operating Reserve Offer Submitted at an Intertie Metering Point	**Available to dispatchable *registered facilities*.** A matrix of up to 5 *price-quantity pairs* offered by *market participant* 'k' to supply *class r reserve* during *settlement hour* 'h'. *Operating reserve offer* submitted in day-ahead, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *intertie metering point* 'i' of *settlement hour* 'h', arranged in ascending order by the offered price in each *price-quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2. Where: r1 = not applicable r2 = 10-minute non-spinning *operating reserve* r3 = 30-minute *operating reserve*

3.5.4.4 Offers and Bids for Virtual Transactions

DAM *market participants* authorized to conduct *virtual transactions* may submit *offers* and *bids*. These *offers* and *bids* are strictly confined to *energy*. Table 3-16 summarizes the attributes of these virtual *offers* and *bids*.

Table 3-16: Description of DAM Offers and Bids for Virtual Transactions

Variable	Name	Description
$DAM\_VBE^{v}_{k,h}$	DAM Virtual Energy Offer	A matrix of up to 20 *price-quantity pairs* offered by *market participant* 'k' to sell *energy* through a virtual transaction during *settlement hour* 'h'. Virtual *energy offer* submitted in day-ahead represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' to sell *energy* at virtual transaction zonal trading entity 'v' of *settlement hour* 'h', arranged in ascending order by the offered price in each *price-quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2.
$DAM\_VBL^{v}_{k,h}$	DAM Virtual Energy Bid	A matrix of up to 20 *price-quantity pairs bid* by *market participant* 'k' to buy *energy* through a virtual transaction during *settlement hour* 'h'. Virtual *energy bid* submitted in day-ahead represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' to sell *energy* at virtual transaction zonal trading entity 'v' of *settlement hour* 'h', arranged in ascending order by the offered price in each *price-quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2.

3.5.4.5 Settlement Input Values Derived from DAM Data

The DAM calculation engine will use both *dispatch data* submitted in the day-ahead market and associated registration data. However, the *settlement process* will not receive these data elements directly from the DAM calculation engine in their final form. The *settlement process* will derive *settlement* input values from a combination of *bid* or *offer* data and DAM calculation engine data. This is particularly relevant in the *settlement* of combined-cycle plants using *pseudo-unit* (PSU) modelling.

- **Economic Operating Point:** The implementation of a single schedule market will introduce a new concept of the economic operating point (EOP). The EOP indicates the optimum operating point of a *generation facility* or *dispatchable load* that is implied by the day-ahead *market price*. A generation or load *facility's* EOP is a point on its *offer* or *bid* curve that is a function of the day-ahead LMP and the *generation facility's* or *dispatchable load's* day-ahead financial binding schedule. Section 3.7.1describes the EOP in further detail in the context of the DAM_MWP.

- **Facility-based *offers* for units modelled as PSUs**: Under MRP, *pseudo-unit* modelling will be available in all timeframes from DAM through to real-time. The PSU model used in DACP today will be carried forward into the new *energy market* to construct *facility*-based schedules and *offers*. The *settlement process* will derive the *facility*-based *offers* from submitted PSU *offers* using the Derived Interval Price Curve (DIPC) and derive the ST *energy* schedule eligible for cost recovery using the Derived Interval Guarantee Quantity (DIGQ) formulation methodology. The DAM calculation engine will translate the PSU schedules into physical unit (PU) schedules and provide these to the *settlement process* before the *settlement* calculations take place.

Table 3-17: Description of Settlement Input Values Derived from DAM Data

Variable	Name	Description
$DAM\_MWP\_DIPC^{c}_{k,h}$	DAM Make-Whole Payment Derived Interval Price Curve at a Combustion Turbine	DAM *energy* price curves derived from submitted hourly day-ahead PSU *energy offers*, for DAM Make-Whole Payment *settlement*, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at combustion turbine *delivery point* 'c' of *settlement hour* 'h', arranged in ascending order by the offered price in each *price-quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2.
$DAM\_QSI\_DIPC^{c}_{k,h}$	DAM Quantity of Energy Scheduled for Injection Derived Interval Price Curve at a Combustion Turbine	DAM *energy* price curves derived from submitted hourly day-ahead PSU *energy offers* and *dispatch* quantity of *energy* scheduled for injection, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at combustion turbine *delivery point* 'c' of *settlement hour* 'h', arranged in ascending order by the offered price in each *price quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2.
$DAM\_QSI\_DIPC^{s}_{k,h}$	DAM Quantity of Energy Scheduled for Injection Derived Interval Price Curve at a Steam Turbine	DAM *energy* price curves derived from submitted hourly day-ahead PSU *energy offers* and *dispatch* quantity of *energy* scheduled for injection, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at steam turbine *delivery point* 's' of *settlement hour* 'h', arranged in ascending order by the offered price in each *price quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2.
$DAM\_QSI\_DIGQ^{s}_{k,h}$	DAM Quantity of Energy Scheduled for Injection Derived Interval Guaranteed Quantity at a Steam Turbine	Portion of the day-ahead quantity of *energy* scheduled for injection, derived from day-ahead PSU *energy* schedules for *market participant* 'k' at steam turbine *delivery point* 's' of *settlement hour* 'h'. This is the total ST share of all quantities that the DAM calculation engine has scheduled for injection by the set of PSUs associated with the ST, excluding any PSUs with schedules below their MLP.
$DAM\_QSOR\_DIPC^{c}_{r,k,h}$	DAM Quantity Schedule of Operating Reserve Derived Interval Price Curve at a Combustion Turbine	DAM *class r reserve* price curves derived from submitted hourly day-ahead PSU *class r reserve offers* and scheduled quantity of *class r reserve*, for *market participant* 'k' at combustion turbine *delivery point* 'c' of *settlement hour* 'h'. Where: r1 = 10-minute spinning *operating reserve* r2 = 10-minute non-spinning *operating reserve* r3 = 30-minute *operating reserve*

Variable	Name	Description
$DAM\_QSOR\_DIPC^{s}_{r,k,h}$	DAM Quantity Schedule of Operating Reserve Derived Interval Price Curve at a Steam Turbine	DAM *class r reserve* price curves derived from submitted hourly day-ahead PSU *class r reserve offers* and scheduled quantity of *class r reserve*, for *market participant* 'k' at steam turbine *delivery point* 's' of *settlement hour* 'h'. Where: r1 = 10-minute spinning *operating reserve* r2 = 10-minute non-spinning *operating reserve* r3 = 30-minute *operating reserve*
$DAM\_QSOR\_DIGQ^{s}_{r,k,h}$	DAM Quantity Schedule of Operating Reserve Derived Interval Guaranteed Quantity at a Steam Turbine	Portion of the day-ahead quantity of *class r reserve* schedule derived from day-ahead PSU *class r reserve* schedules for *market participant* 'k' at steam turbine *delivery point* 's' of *settlement hour* 'h'. Where: r1 = 10-minute spinning *operating reserve* r2 = 10-minute non-spinning *operating reserve* r3 = 30-minute *operating reserve* This is the total ST share of all quantities of *class r reserve* that the DAM calculation engine has scheduled for delivery at the set of PSUs associated with the ST.
$DAM\_EOP^{m}_{k,h}$	DAM Economic Operating Point at a Delivery Point	DAM economic operating point for *market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h'.
$DAM\_EOP^{i}_{k,h}$	DAM Economic Operating Point at an Intertie Metering Point	DAM economic operating point for *market participant* 'k' at *intertie metering point* 'i' in *settlement hour* 'h'.
$DAM\_EOP^{c}_{k,h}$	DAM Economic Operating Point at a Combustion Turbine	DAM economic operating point for *market participant* 'k' at combustion turbine *delivery point* 'c' in *settlement hour* 'h'.
$DAM\_EOP^{m}_{r,k,h}$	DAM Economic Operating Point of Operating Reserve at a Delivery Point	DAM economic operating point of *class r reserve* for *market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h'. Where: r1 = 10-minute spinning *operating reserve* r2 = 10-minute non-spinning *operating reserve* r3 = 30-minute *operating reserve*

Variable	Name	Description
$\mathrm{DAM\_EOP}^{i}_{r,k,h}$	DAM Economic Operating Point of Operating Reserve at an Intertie Metering Point	DAM economic operating point of *class r reserve* for *market participant* 'k' at *intertie metering point* 'i' in *settlement hour* 'h'. Where: r1 = 10-minute spinning *operating reserve* r2 = 10-minute non-spinning *operating reserve* r3 = 30-minute *operating reserve*
$\mathrm{DAM\_EOP}^{c}_{r,k,h}$	DAM Economic Operating Point of Operating Reserve at a Combustion Turbine	DAM economic operating point of *class r reserve* for *market participant* 'k' at combustion turbine *delivery point* 'c' of *settlement hour* 'h'. Where: r1 = 10-minute spinning *operating reserve* r2 = 10-minute non-spinning *operating reserve* r3 = 30-minute *operating reserve*
$\mathrm{DAM\_EOP\_DIPC}^{s}_{k,h}$	DAM Economic Operating Point Derived Interval Price Curve at a Steam Turbine	DAM economic operating point of *energy* price curves derived from submitted hourly day-ahead PSU *energy offers*, represented as a N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at steam turbine *delivery point* 's' of *settlement hour* 'h', arranged in ascending order by the offered price in each *price-quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2.
$\mathrm{DAM\_EOP\_DIGQ}^{s}_{k,h}$	DAM Economic Operating Point Derived Interval Guaranteed Quantity at a Steam Turbine	DAM economic operating point of the portion of the day-ahead quantity of *energy* scheduled for injection derived from day-ahead PSU *energy* schedules for *market participant* 'k' at steam turbine *delivery point* 's' of *settlement hour* 'h'. This is the sum total of the ST shares of DAM lost cost EOP for *energy* for every PSU that is associated with the ST and has a DAM financially binding schedule above MLP.
$\mathrm{DAM\_OR\_EOP}^{m}_{r,k,h}$	DAM Economic Operating Point for Operating Reserve at a Delivery Point	DAM economic operating point of *class r reserve* for *market participant* 'k' at *delivery point* 'm' of *settlement hour* 'h'. Where: r1 = 10-minute spinning *operating reserve* r2 = 10-minute non-spinning *operating reserve* r3 = 30-minute *operating reserve*

Variable	Name	Description
$DAM\_OR\_EOP\_DIPC^{s}_{r,k,h}$	DAM Economic Operating Point for Operating Reserve - Derived Interval Price Curve at a Steam Turbine	DAM economic operating point of *class r reserve* price curves derived from submitted hourly day-ahead PSU *class r reserve offers*, represented as a N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at steam turbine *delivery point* 's' of *settlement hour* 'h', arranged in ascending order by the offered price in each *price-quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2. Where: r1 = 10-minute spinning *operating reserve* r2 = 10-minute non-spinning *operating reserve* r3 = 30-minute *operating reserve*
$DAM\_OR\_EOP\_DIGQ^{s}_{r,k,h}$	DAM Economic Operating Point for Operating Reserve - Derived Interval Guaranteed Quantity at a Steam Turbine	DAM economic operating point of the portion of the day-ahead quantity of *class r reserve* scheduled for injection derived from day-ahead PSU *class r reserve* schedules for *market participant* 'k' at steam turbine *delivery point* 's' of *settlement hour* 'h'. Where: r1 = 10-minute spinning *operating reserve* r2 = 10-minute non-spinning *operating reserve* r3 = 30-minute *operating reserve* This is the sum total of the ST shares of DAM lost cost EOP for *class r reserve* for every PSU that is associated with the ST and has a DAM financially binding schedule above MLP.

3.5.4.6 DAM PBC Data

In the future market, the *real-time market physical bilateral contract data* (PBC data) will continue to be collected and used. In addition, the DAM PBC data will also be collected in the same manner and form as the *real-time market* data.

Table 3-18: DAM PBC Quantities Collected by the Settlement Process

Variable	Name	Description
$DAM\_BCQ^{m}_{s,k,h}$	DAM Physical Bilateral Contract Quantity of Energy Bought at a Delivery Point	DAM *physical bilateral contract quantity* of *energy*, in MWh, bought by *buying market participant* 'k' from *selling market participant* 's' at *delivery point* 'm' in *settlement hour* 'h'. **Unit of measurement:** MWh **Time resolution:** hourly
$DAM\_BCQ^{m}_{k,b,h}$	DAM Physical Bilateral Contract Quantity of Energy Sold at a Delivery Point	DAM *physical bilateral contract quantity* of *energy*, in MWh, sold by *selling market participant* 'k' to *buying market participant* 'b' at *delivery point* 'm' in *settlement hour* 'h'. **Unit of measurement:** MWh **Time resolution:** hourly

Variable	Name	Description
$DAM\_BCQ^{i}_{s,k,h}$	DAM Physical Bilateral Contract Quantity of Energy Bought at an Intertie Metering Point	DAM *physical bilateral contract quantity* of *energy*, in MWh, bought by *market participant* 'k' from *selling market participant* 's' at *intertie metering point* 'i' in *settlement hour* 'h'. **Unit of measurement:** MWh **Time resolution:** hourly
$DAM\_BCQ^{i}_{k,b,h}$	DAM Physical Bilateral Contract Quantity of Energy Sold at an Intertie Metering Point	DAM *physical bilateral contract quantity* of *energy*, in MWh, sold by *selling market participant* 'k' to *buying market participant* 'b' at *intertie metering point* 'i' in *settlement hour* 'h'. **Unit of measurement:** MWh **Time resolution:** hourly
$DAM\_RQ^{m,i}_{k,h}$	DAM Reallocate Quantity	DAM quantity derived from a *physical bilateral contract quantity* in order to reallocate a component of *hourly uplift* from the *buying market participant* to the *selling market participant* in direct proportion to the size of the DAM *physical bilateral contract.* $DAM\_RQ^{m,i}_{k,h} = \sum_{s,b}[(DAM\_BCQ^{m}_{k,b,h} + (DAM\_BCQ^{i}_{k,b,h}) - (DAM\_BCQ^{m}_{s,k,h} + DAM\_BCQ^{i}_{s,k,h})]$

PBC quantities must be received by the *settlement process* prior to the first calculation run for a given *trading day* so that such quantities are accounted for when calculating the *actual exposure* of a *market participant* for prudential purposes.

Similar to the *real-time market* PBC quantities, all DAM PBC quantities:

- have a designated *selling market participant* and a designated *buying market participant;*
- will be submitted by the *selling market participant* only;
- can be submitted:
  - 7 calendar days prior to the *trading day* to which they pertain;
  - on the *trading day* to which they pertain; or
  - 6 *business days* after the *trading day*;
- will be associated with a single *delivery point* or *intertie metering point*;
- can be in the form of standing DAM *physical bilateral contract data* that can be in effect over multiple *trading days*; and
- can be derived from other data. Specifically, DAM PBC quantities can be derived from the physical transaction schedule data produced by the DAM calculation engine, so long as the schedule belongs to either the *selling market participant* or the *buying market participant*.

3.5.4.7 Allocation of DAM Uplift Amounts Using PBCs

The *buying market participant* may transfer DAM PBC quantities of various *hourly uplift settlement amounts* to the *selling market participant* in proportion to the PBC contract quantity. Specifically, the *selling market participant* will be able to assume a portion of the following hourly DAM uplift amounts:

- DAM Operating Reserve Uplift; and
- DAM Balancing Credit Uplift.

The quantity applied to the calculation of the *settlement amounts* is determined as follows:

- Each *hourly uplif*t component may be selected in any combination when the DAM PBC data is submitted by the *selling market participant*;
- Selecting an *hourly uplif*t component within DAM PBC data creates a DAM Reallocate Quantity (DAM_RQ);
- The DAM_RQ specific to a single PBC is exactly equal to the quantity of *energy* involved in the contract itself;
- The DAM_RQ specific to a single *market participant* is equal to the sum of all DAM RQ quantities for which the *market participant* is the *selling market participant*, minus the sum of all DAM RQ quantities for which the *market participant* is the *buying market participant*;
- The DAM_RQ specific to a single *market participant* for a particular DAM *hourly uplif*t component is equal to the sum of all DAM_RQ quantities designated for that particular DAM *hourly uplift* component within DAM *physical bilateral contract data* for which the *market participant* is the *selling market participant*, minus the sum of all DAM_RQ quantities for which the *market participant* is the *buying market participant*; and
- This DAM_RQ quantity is then applied to the calculation of the *settlement amounts* for each *hourly uplift* component.

Therefore, when calculating the DAM_RQ quantity for a particular *hourly uplift* component for *market participant* 'k' at a particular *delivery point* 'm' or *intertie metering point* 'i', for *settlement hour* 'h', the quantity may be expressed as follows:

$$DAM\_RQ_{k,h}^{m,i} = \sum_{s,b}[(DAM\_BCQ_{k,b,h}^{m} + (DAM\_BCQ_{k,b,h}^{i}) - (DAM\_BCQ_{s,k,h}^{m} + DAM\_BCQ_{s,k,h}^{i})]$$

Where:

's' is the *selling market participant.*

'b' is the *buying market participant.*

The DAM_RQ quantity is then used to either increase or decrease the *settlement amount* for the *charge type* 'c' as follows:

Hourly Uplift Amount = $\sum TD_{h,c}$ x [({participant's share of allocation base} + $DAM\_RQ_{k,h}^{m,i}$) / $\sum_k^M$ (total allocation base)]

Where:

$TD_{h,c}$ is the total dollar value of the *hourly uplift settlement amount* for the *charge type* 'c' being allocated to the *IESO-administered markets* during *settlement hour* 'h'.

‘M’	is the set of all *registered wholesale meters* (*RWM) or intertie metering points* ‘m’.
‘c’	is a type of *hourly uplift settlement amount* from the list at the beginning of this section.

In the event that the term, (allocation base + $DAM\_RQ_{k,h}^{m,i}$) < 0

Where:

$DAM\_RQ_{k,h}^{m,i} < 0$ and $|DAM\_RQ_{k,h}^{m,i}| > |$(participant’s share of allocation base)$|$ and $TD_{k,h,c} > 0$

The calculation of the applicable *hourly uplift* component will yield a net credit to the *buying market participant* as a result of the reallocated quantity exceeding their share of the allocation base.

3.5.5 Collection of Pre-Dispatch Data

3.5.5.1 PD Calculation Engine

Data produced by the PD calculation engine will be sent to the *settlement process* to support the calculations for NQS *generation facilities* and *intertie* transactions.

The tables that follow in this section describe the *settlement* variables that will be received by the *settlement process* from the PD calculation engine, grouping the variables into the following categories:

1. Advisory prices;
2. Advisory schedules;
3. Mitigation results;
4. PD unit commitment events; and
5. Other.

Where applicable, the *settlement* variables listed in these tables will be used throughout this document in the description of various PD *settlement* calculations.

The variables described in these tables are new and will be calculated by the PD calculation engine on an hourly basis during the pre-dispatch time period, and will then pass through any subsequent verification and quality control processes, resulting in *settlement*-ready data.

Table 3-19 lists the prices received from the PD calculation engine.

Table 3-19: Prices Received from the PD Calculation Engine

Variable	Name	Description
$PD\_LMP_h^m$	Pre-Dispatch Locational Marginal Price of Energy at a Delivery Point	Pre-dispatch *energy market price* at *delivery point* ‘m’ of *settlement hour* ’h’. **Unit of measurement:** $/MWh to the nearest cent **Time resolution:** hourly
$PD\_LMP_h^i$	Pre-Dispatch Locational Marginal Price of Energy at an Intertie Metering Point	Pre-dispatch *energy market price* at *intertie metering point* ‘i’ of *settlement hour* ’h’. **Unit of measurement:** $/MWh to the nearest cent **Time resolution:** hourly

Variable	Name	Description
$PD\_LMP_{h}^{m,pdr}$	Pre-Dispatch Locational Marginal Price of Energy at a Delivery Point for a Given Pre-Dispatch Run	Pre-dispatch *energy market price* at *delivery point* ‘m’ of *settlement hour* ’h’ for a given pre-dispatch run ‘pdr’. Where: pdm = pre-dispatch run that issued the most recent binding start-up instruction or commitment extension for a single *delivery point* ‘m’ pd1 = hour-ahead pre-dispatch run in the hour preceding *settlement hour* ‘h’ pdc = Not applicable pdi = Not applicable **Unit of measurement:** $/MWh to the nearest cent **Time resolution:** hourly
$PD\_LMP_{h}^{c,pdr}$	Pre-Dispatch Locational Marginal Price of Energy at a Combustion Turbine for a Given Pre-Dispatch Run	Pre-dispatch *energy market price* at combustion turbine *delivery point* ‘c’ of *settlement hour* ’h’ for a given pre-dispatch run ‘pdr’. Where: pdm = pre-dispatch run that issued the most recent binding start-up instruction or commitment extension for a single *delivery point* ‘m’ pd1 = hour-ahead pre-dispatch run in the hour preceding *settlement hour* ‘h’ pdc = Not applicable pdi = Not applicable **Unit of measurement:** $/MWh to the nearest cent **Time resolution:** hourly
$PD\_LMP_{h}^{s,pdr}$	Pre-Dispatch Locational Marginal Price of Energy at a Steam Turbine for a Given Pre-dispatch Run	Pre-dispatch *energy market price* at steam turbine *delivery point* ‘s’ of *settlement hour* ’h’ for a given pre-dispatch run ‘pdr’. Where: pdm = Not applicable pd1 = hour-ahead pre-dispatch run in the hour preceding *settlement hour* ‘h’ pdc = pre-dispatch run that issued the most recent binding start-up instruction or commitment extension at CT ‘c’ as of *metering interval* ‘t’ pdi = Not applicable **Unit of measurement:** $/MWh to the nearest cent **Time resolution:** hourly

Table 3-20 lists the schedules received from the PD calculation engine.

Table 3-20: Schedules Received from the PD Calculation Engine

Variable	Name	Description
$PD\_QSI^{i}_{k,h}$	Pre-Dispatch Quantity of Energy Scheduled for Injection at an Intertie Metering Point	Pre-dispatch quantity of *energy* scheduled for injection by *market participant* 'k' at *intertie metering point* 'i' of *settlement hour* 'h'. **Unit of measurement:** MWh **Time resolution:** hourly
$PD\_QSI^{m,pdr}_{k,h}$	Pre-Dispatch Quantity of Energy Scheduled for Injection at a Delivery Point for a Given Pre-Dispatch Run	Pre-dispatch quantity of *energy* scheduled for injection by *market participant* 'k' at *delivery point* 'm' of *settlement hour* 'h' for a given pre-dispatch run 'pdr'. Where: pdm = pre-dispatch run that issued the most recent binding start-up instruction or commitment extension for a single *delivery point* 'm' pd1 = Not applicable pdc = Not applicable pdi = Not applicable **Unit of measurement:** MWh **Time resolution:** hourly
$PD\_QSI^{c,pdr}_{k,h}$	Pre-Dispatch Quantity of Energy Scheduled for Injection at a Combustion Turbine for a Given Pre-Dispatch Run	Pre-dispatch quantity of *energy* scheduled for injection by *market participant* 'k' at combustion turbine *delivery point* 'c' of *settlement hour* 'h' for a given pre-dispatch run 'pdr'. Where: pdm = pre-dispatch run that issued the most recent binding start-up instruction or commitment extension for a single *delivery point* 'm' pd1 = Not applicable pdc = Not applicable pdi = Not applicable **Unit of measurement:** MWh **Time resolution:** hourly
$PD\_QSW^{i}_{k,h}$	Pre-Dispatch Quantity of Energy Scheduled for Withdrawal at an Intertie Metering Point	Pre-dispatch quantity of *energy* scheduled for withdrawal by *market participant* 'k' at *intertie metering point* 'i' of *settlement hour* 'h'. **Unit of measurement:** MWh **Time resolution:** hourly

The PD calculation engine will perform ex-ante mitigation for economic withholding and produce conduct and price impact test results and mitigated *dispatch data* when such tests result in failure. See the Market Power Mitigation detailed design document for a description of these processes. The PD calculation engine will be the source of mitigated *dispatch data* and test results provided to the *settlement process* for potential *settlement* mitigation of make-whole payments and other guarantee payments.

Table 3-21 identifies the mitigation data provided by the PD calculation engine to the *settlement process* at a summary level.

Table 3-21: Mitigation Results from the PD Calculation Engine

Name	Description
Conduct Test Result	Pass or fail results of units at *delivery point* 'm' undergoing the conduct test for each *dispatch hour* 'h' of the pre-dispatch look-ahead period.
Price Impact Test Result	Pass or fail results of units at *delivery point* 'm' undergoing the price impact test for each *dispatch hour* 'h' of the pre-dispatch look-ahead period.
Mitigated Dispatch Data	Mitigated *dispatch data* enhanced to reflect the most restrictive failed *dispatch data* parameter during the hour or commitment period for the unit that failed the conduct test for *market participant* 'k' at *delivery point* 'm' for each *dispatch hour* 'h' of the pre-dispatch look-ahead period. Potential mitigated financial *dispatch data* parameters include: • *Energy offers* • Start-up offers • Speed no-load offers • *Operating reserve offers* • *Energy offers* for the range of production up to MLP
Resource Constrained Area Mitigation Test Conditions	Constrained area mitigation condition for each resource at *delivery point* 'm' prevailing during each *settlement hour* 'h' of the pre-dispatch look-ahead period. The relevant impact threshold used in MWP impact testing for *market participant* 'k' will be applied depending on the constrained area condition under which the resource failed the conduct test. See Table 3-22: PD Thresholds from the Market Power Mitigation Information System.

Table 3-22 identifies the PD mitigation data provided by the Market Power Mitigation Information System to the *settlement process*.

Table 3-22: PD Thresholds from the Market Power Mitigation Information System

Name	Description
Make-Whole Payment Impact Test Thresholds	The relevant impact threshold used in make-whole payment impact testing for *market participant* 'k' will be applied depending on the constrained area condition under which the resource failed the conduct test: • Broad constrained area (BCA) for *energy* • Narrow constrained area (NCA) for *energy* • Dynamic constrained area (DCA) for *energy* • Reliability constraint for *energy* • Global market power for *energy* • Global market power for *operating reserve* • Local market power for *operating reserve* Refer to the Market Power Mitigation detailed design, Table 3-3 for mitigation conditions for make-whole payment impact testing.

PD unit commitments, under normal circumstances and when there is a *reliability* need, are necessary for the operation of NQS resources. The commitments are made in the PD timeframe to account for the operational characteristics of the NQS resources.

Table 3-23 identifies the two types of PD unit commitments required by the *settlement process*.

Table 3-23: PD Unit Commitment Events

Name	Description
PD Unit Commitment Events	Unit commitments made during the pre-dispatch timeframe.
PD Reliability Unit Commitment Events	Manual unit commitments made during the pre-dispatch timeframe by the *IESO* for *reliability* reasons.

Table 3-24 lists the data provided by the PD calculation engine to the *settlement process* that is required in the calculation of the generator failure charge, which is discussed in Section 3.7.11.

Table 3-24: Other Data Received from the PD Calculation Engine

Variable	Name	Description
$\text{PD\_MGBRT}_{k,f}^{m}$	Pre-Dispatch MGBRT Duration Associated with a Delivery Point Failure	Pre-dispatch MGBRT in *metering intervals* that is part of the PD commitment associated with failure 'f' at *delivery point* 'm' and does not overlap with a DAM commitment. **Unit of measurement:** hours

Variable	Name	Description
$PD\_MGBRT_{k,f}^{c}$	Pre-Dispatch MGBRT Duration Associated with a Combustion Turbine Failure	Pre-dispatch MGBRT in *metering intervals* that is part of the PD commitment associated with failure ‘f’ at combustion turbine *delivery point* ‘c’ and not part of a DAM financially binding schedule above MLP. **Unit of measurement:** hours
$SU\_INCR_{k,f}^{m}$	Incremental Start-Up Offer for a Delivery Point Associated with a Failure	**Available to eligible *generation facilities.*** Incremental start-up offer associated with financial *offers* at *delivery point* ‘m’ for *market participant* ‘k’ for the PD commitment that has a failure ‘f’. **Unit of measurement:** $ (dollar rounded to the nearest cent *per-start*)
$SU\_INCR_{k,f}^{m,pdr}$	Incremental Start-Up Offer for a Delivery Point with a Failure in a Given Pre-Dispatch Run	**Available to eligible *generation facilities.*** Incremental start-up offer associated with financial *offers* at *delivery point* ‘m’ for *market participant* ‘k’ that was offered into a given pre-dispatch run ‘pdr’. It represents the start-up offers that are incremental to any existing DAM commitments. Where: pdm = pre-dispatch run that issued the most recent binding start-up instruction or commitment extension for a single *delivery point* ‘m’ pd1 = Not applicable pdc = Not applicable pdi = Not applicable **Unit of measurement:** $ (dollar rounded to the nearest cent *per-start*)
$SU\_INCR_{k,f}^{p,pdr}$	Incremental Start-Up Offer for a Pseudo-Unit with a Failure in a Given Pre-Dispatch Run	**Available to eligible *generation facilities* associated with a *pseudo-unit.*** Incremental start-up offer associated with financial *offers* at *pseudo-unit* ‘p’ for *market participant* ‘k’ that was offered into a given pre-dispatch run ‘pdr’. It represents the start-up offers that are incremental to any existing DAM commitments. Where: pdm = Not applicable pd1 = Not applicable pdc = Not applicable pdi = pre-dispatch run that issued the binding start-up instruction for the PD commitment period that the CT failure ‘f’ occurred in **Unit of measurement:** $ (dollar rounded to the nearest cent *per-start*)
$STP\_SU\_INCR_{k,f}^{p,pdr}$	Steam Turbine Portion of Incremental Start-Up Offer for a	**Available to eligible *generation facilities* associated with a *pseudo-unit.***

Variable	Name	Description
	Pseudo-Unit with a Failure in a Given Pre-Dispatch Run	Steam turbine portion of incremental start-up offer associated with financial *offers* at *pseudo-unit* 'p' for *market participant* 'k' that was offered into a given pre-dispatch run 'pdr'. It represents the start-up offers that are incremental to any existing DAM commitments. Where: pdm = Not applicable pd1 = Not applicable pdc = Not applicable pdi = pre-dispatch run that issued the binding start-up instruction for the PD commitment period that the CT failure 'f' occurred in **Unit of measurement:** $ (dollar rounded to the nearest cent *per-start*)
$PD\_SU\_MLP_{k,f}^{m}$	Pre-Dispatch Start-Up Offer Failure Proportion for a Delivery Point Associated with a Failure	The proportion of the pre-dispatch start-up offer associated with financial *offers* at *delivery point* 'm' for *market participant* 'k' that shall be included in the Generator Failure Charge – Guarantee Cost Component equal to the proportion of the total *metering intervals* in period $PD\_MGBRT_{k,f}^{m}$ that are considered failure intervals 'f' for the *delivery point*. **Unit of measurement:** $ (dollar rounded to the nearest cent *per-start*)
$PD\_SU\_MLP_{k,f}^{c}$	Pre-Dispatch Start-Up Offer Failure Proportion for a Combustion Turbine Associated with a Failure	The proportion of the pre-dispatch start-up offer associated with financial *offers* at combustion turbine *delivery point* 'c' for *market participant* 'k' that shall be included in the Generator Failure Charge – Guarantee Cost Component equal to the proportion of the total *metering intervals* in period $PD\_MGBRT_{k,f}^{c}$ that are considered failure intervals 'f' for the CT. **Unit of measurement:** $ (dollar rounded to the nearest cent *per-start*)
$MLP\_INJ_{k,f}^{m}$	Injections Below MLP During MGBRT Period Associated with a Delivery Point Failure	Number of failure intervals 'f' at *delivery point* 'm' that occur during the $PD\_MGBRT_{k,f}^{m}$. This represents the number of *metering intervals* with injections below MLP during the MGBRT period associated with a *delivery point* failure. **Unit of measurement:** MW
$MLP\_INJ_{k,f}^{c}$	Injections Below MLP During MGBRT Period Associated with a Combustion Turbine Failure	Number of CT failure intervals 'f' at combustion turbine *delivery point* 'c' that occur during the $PD\_MGBRT_{k,f}^{c}$. This represents the number of *metering intervals* with injections below MLP during the MGBRT period associated with a combustion turbine failure. **Unit of measurement:** MW

3.5.5.2 PD Offer and Bid Data

Market participants will be able to submit and adjust their *offers* and *bids* for physical transactions during the pre-dispatch timeframe. Except for the *offers* and *bids* that have been substituted with reference levels due to ex-ante market power mitigation, all pre-dispatch *offers* and *bids* will be used by the *settlement process* in the form that they were submitted by the *market participant*. If mitigated, the *settlement process* will use the mitigated *offer* or *bid*.

The pre-dispatch *offers* for NQS *generation facilities* will be required for *settlement* purposes by the *settlement process*. Table 3-25 describes the details of these offers.

Table 3-25: Financial Dispatch Data for Physical Transactions Submitted to Pre-Dispatch

Variable	Name	Description
$PD\_BE^{p,t}_{k,h}$	Pre-Dispatch Energy Offer at a Pseudo-Unit	**Available to *generation facilities* associated with a *pseudo-unit.*** A matrix of up to 20 *price-quantity pairs* offered by *market participant* 'k' to supply *energy* during *settlement hour* 'h'. *Energy offers* submitted in pre-dispatch, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *pseudo-unit* 'p' during *metering interval* 't' of *settlement hour* 'h', arranged in ascending order by the offered price in each *price-quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2.
$PD\_BE^{m,pdr}_{k,h}$	Pre-Dispatch Energy Offer for a Given Pre-Dispatch Run	A matrix of up to 20 *price-quantity pairs* offered by *market participant* 'k' to supply *energy* during *settlement hour* 'h'. *Energy offers* submitted in pre-dispatch, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *delivery point* 'm' of *settlement hour* 'h' in a given pre-dispatch run 'pdr', arranged in ascending order by the offered price in each *price-quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2. Where: pdm = pre-dispatch run that issued the most recent binding start-up instruction or commitment extension for a single *delivery point* 'm' pd1 = Not applicable pdc = Not applicable pdi =Not applicable
$PD\_BOR^{p,t}_{r,k,h}$	Pre-Dispatch Operating Reserve Offer Submitted at a Pseudo-Unit	**Available to dispatchable *registered facilities*.** A matrix of up to 5 *price-quantity pairs* offered by *market participant* 'k' to supply class 'r' *operating reserve* during *settlement hour* 'h'. *Operating reserve offer* submitted in pre-dispatch, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *pseudo-unit* 'p' during *metering interval* 't' of *settlement hour* 'h', arranged in ascending order by the offered price in each *price-quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2. Where:

Variable	Name	Description
		r1 = 10-minute spinning *operating reserve* r2 = 10-minute non-spinning *operating reserve* r3 = 30-minute *operating reserve*
$PD\_BE\_SU_{k,h}^{m}$	Pre-Dispatch Start-Up Offer *(physical transactions only)*	**Available to eligible *generation facilities*.** Pre-dispatch start-up offer associated with financial *offers* for the first *settlement hour* 'h' of the PD commitment period at *delivery point* 'm' for *market participant* 'k' *per-start.* **Unit of measurement:** $ (dollar rounded to the nearest cent *per-start*)
$PD\_BE\_SU_{k,h}^{p}$	Pre-Dispatch Start-Up Offer for a Pseudo-Unit *(physical transactions only)*	**Available to eligible *generation facilities* associated with a *pseudo-unit.*** Pre-dispatch start-up offer associated with financial *offers* for a given *settlement hour* 'h' at *pseudo-unit* 'p' for *market participant* 'k' *per-start.* **Unit of measurement:** $ (dollar rounded to the nearest cent *per-start*)
$PD\_BE\_SU_{k,f}^{m,pdr}$	Pre-Dispatch Start-Up Offer Submitted in a Given Pre-Dispatch Run for a Delivery Point with a Failure *(physical transactions only)*	**Available to eligible *generation facilities.*** Pre-dispatch start-up offer associated with financial *offers*, subject to mitigation, upon which *delivery point* 'm' for *market participant* 'k' was committed in the pre-dispatch run 'pdr' for the PD commitment that has a failure 'f'. Where pdm = pre-dispatch run that issued the most recent binding start-up instruction or commitment extension for a single *delivery point* 'm' pd1 = Not applicable pdc = Not applicable pdi = Not applicable **Unit of measurement:** $ (dollar rounded to the nearest cent *per-start*)
$PD\_BE\_SU_{k,f}^{p,pdr}$	Pre-Dispatch Start-Up Offer Submitted in a Given Pre-Dispatch Run for a Pseudo-Unit Commitment Period with a Combustion Turbine Failure *(physical transactions only)*	**Available to eligible *generation facilities* associated with a *pseudo-unit*.** Pre-dispatch start-up offer associated with financial *offers* at *pseudo-unit* 'p' for *market participant* 'k' that was offered into a given pre-dispatch run 'pdr' that issued a PD commitment during which a combustion turbine failure 'f' occurred. Where: pdm = Not applicable pd1 = Not applicable pdc = Not applicable

Variable	Name	Description
		pdi = pre-dispatch run that issued the binding start-up instruction for the PD commitment period that the CT failure ‘f’ occurred in. **Unit of measurement:** $ (dollar rounded to the nearest cent *per-start*)
$PD\_BE\_SNL^{m}_{k,h}$	Pre-Dispatch Speed No-Load Offer *(physical transactions only)*	**Available to eligible *generation facilities*.** Speed no-load offer associated with financial *offers* for a given *settlement hour* ‘h’ at *delivery point* ‘m’ for *market participant* ‘k’. **Unit of measurement:** $ (dollar rounded to the nearest cent)
$PD\_BE\_SNL^{p}_{k,h}$	Pre-Dispatch Speed No-Load Offer for a Pseudo-Unit *(physical transactions only)*	**Available to eligible *generation facilities* associated with a *pseudo-unit.*** Speed no-load offer associated with financial *offers* for a given *settlement hour* ‘h’ at *pseudo-unit* ‘p’ for *market participant* ‘k’. **Unit of measurement:** $ (dollar rounded to the nearest cent)
$PD\_BE\_SNL^{m,pdr}_{k,h}$	Pre-Dispatch Speed No-Load Offer for a Delivery Unit for a Given Pre-dispatch Run	**Available to eligible *generation facilities*.** Speed no-load offer associated with financial *offers* for a given *settlement hour* ‘h’ at *delivery point* ‘m’ for *market participant* ‘k’ that was offered into a given pre-dispatch run ‘pdr’. Where: pdm = pre-dispatch run that issued the most recent binding start-up instruction or commitment extension for a single *delivery point* ‘m’ pd1 = Not applicable pdc = Not applicable pdi = Not applicable **Unit of measurement:** $ (dollar rounded to the nearest cent)
$PD\_BE\_SNL^{p,pdr}_{k,h}$	Pre-Dispatch Speed No-Load Offer for a Pseudo-Unit for a Given Pre-Dispatch Run	**Available to eligible *generation facilities* associated with a *pseudo-unit.*** Speed no-load offer associated with financial *offers* for a given *settlement hour* ‘h’ at *pseudo-unit* ‘p’ for *market participant* ‘k’ that was offered into a given pre-dispatch run ‘pdr’. Where: pdm = Not applicable pd1 = Not applicable pdc = pre-dispatch run that issued the most recent binding start-up instruction (BSUI) or commitment extension at CT ‘c’ as of *metering interval* ‘t’ pdi = Not applicable **Unit of measurement:** $ (dollar rounded to the nearest cent)

3.5.5.3 Settlement Input Values Derived from PD Data

Similar to the day-ahead market, the *settlement process* will derive *settlement* input values from a combination of *bid* or *offer* data and PD calculation engine data that will be used in the *settlement* calculation. This is particularly relevant in the *settlement* of combined-cycle plants using *pseudo-unit* (PSU) modelling.

As previously noted in Section 3.5.4, PSU modelling will be available in all timeframes from DAM through to real-time. In the PD timeframe, the PD calculation engine will translate the PSU schedules into PU schedules and provide these to the *settlement process* before the *settlement* calculations take place.

Table 3-26: Description of Settlement Input Values Derived from PD Data

Variable	Name	Description
$\text{GFC\_GCC\_DIPC}_{k,h}^{c,t}$	Generator Failure Charge - Guarantee Cost Component Derived Interval Price Curve at a Combustion Turbine	Generator Failure Charge – Guarantee Cost Component *energy* price curves derived from *energy offers* submitted into the pre-dispatch run 'pdc' and the *pre-dispatch schedules* issued by that same pre-dispatch run. This variable is represented as a N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at combustion turbine *delivery point* 'c' during *metering interval* 't' of *settlement hour* 'h', arranged in ascending order by the offered price in each *price-quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2. Where: pdc = pre-dispatch run that issued the most recent binding start-up instruction (BSUI) or commitment extension at CT 'c' as of *metering interval* 't'
$\text{GFC\_GCC\_DIPC}_{k,h}^{s,t}$	Generator Failure Charge – Guarantee Cost Component Derived Interval Price Curve at a Steam Turbine	Generator Failure Charge – Guarantee Cost Component *energy* price curves derived from *energy offers* and *pre-dispatch schedules* for each PSU that is associated with the steam turbine 's' and has a CT failure interval coinciding with *metering interval* 't'. This variable is represented as a N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at steam turbine *delivery point* 's' during *metering interval* 't' of *settlement hour* 'h', arranged in ascending order by the offered price in each *price-quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2. The *energy offers* and *pre-dispatch schedules* for each included PSU will be taken from the pre-dispatch run 'pdc' where 'c' is the CT *delivery point* associated with that PSU. Where: pdc = pre-dispatch run that issued the most recent binding start-up instruction (BSUI) or commitment extension at CT 'c' as of *metering interval* 't'

Variable	Name	Description
$\mathrm{GFC\_GCC\_DIGQ}_{k,h}^{s,t}$	Generator Failure Charge – Guarantee Cost Component Derived Interval Guaranteed Quantity at a Steam Turbine	The derived interval guaranteed quantity for *market participant* 'k' at steam turbine *delivery point* 's' during *metering interval* 't' of *settlement hour* 'h'. This variable represents the total steam turbine portion of the *pre-dispatch schedules* for each PSU that is associated with the steam turbine 's' and has a CT failure interval coinciding with *metering interval* 't'. The *pre-dispatch schedule* for each included PSU will be taken from the pre-dispatch run 'pdc' where 'c' is the CT *delivery point* associated with that PSU. Where: pdc = pre-dispatch run that issued the most recent binding start-up instruction (BSUI) or commitment extension at CT 'c' as of *metering interval* 't'
$\mathrm{PD\_STP\_QSI}_{k,h}^{p,pdr}$	Pre-Dispatch Steam Turbine Portion Derived Quantity of Energy Scheduled for Injection at a Pseudo-Unit for a Given Pre-Dispatch Run	Pre-dispatch steam turbine portion of the derived quantity of *energy* scheduled for injection by *market participant* 'k' at *pseudo-unit* 'p' of *settlement hour* 'h' for a given pre-dispatch run 'pdr'. Where: pdm = Not applicable pd1 = Not applicable pdc = pre-dispatch run that issued the most recent binding start-up instruction (BSUI) or commitment extension at CT 'c' as of *metering interval* 't' pdi = Not applicable **Unit of measurement:** MWh **Time resolution:** hourly

3.5.6 Collection of Real-Time Market Data

3.5.6.1 RT Calculation Engine

The introduction of locational marginal prices (LMPs) and ex-ante market power mitigation will require changes in the data that will be collected from the RT calculation engine.

The tables that follow in this section describe the new *settlement* variables that will be received by the *settlement process* from the RT calculation engine, grouping the variables into the following categories:

1. Prices;
2. Schedules;
3. Mitigation results; and
4. Other.

Table 3-27 lists the prices received from the RT calculation engine.

Table 3-27: Prices Received from the RT Calculation Engine

Variable	Name	Description
$RT\_LMP_h^z$	Real-Time Zonal Locational Marginal Price of Energy	Real-time *energy market price* at zone ‘z’ of *settlement hour* ‘h’. Where: z = Ontario zone **Unit of measurement:** $/MWh to the nearest cent **Time resolution:** hourly
$RT\_LMP_h^{m,t}$	Real-Time Locational Marginal Price of Energy at a Delivery Point	Real-time *energy market price* at *delivery point* ‘m’ in *metering interval* ‘t’ of *settlement hour* ’h’, including the LMP for all *non-dispatchable loads* at *delivery point* ‘m’. **Unit of measurement:** $/MWh to the nearest cent **Time resolution:** interval
$RT\_LMP_h^{v,t}$	Real-Time Locational Marginal Price of Energy at a Virtual Transaction Zonal Trading Entity	Real-time *energy market price* at virtual transaction zonal trading entity ‘v’ in *metering interval* ‘t’ of *settlement hour* ’h’. **Unit of measurement:** $/MWh to the nearest cent **Time resolution:** hourly
$RT\_LMP_h^{c,t}$	Real-Time Locational Marginal Price of Energy at a Combustion Turbine	Real-time *energy market price* at combustion turbine *delivery point* ‘c’ in *metering interval* ‘t’ of *settlement hour* ‘h’. **Unit of measurement:** $/MWh to the nearest cent **Time resolution**: interval
$RT\_LMP_h^{s,t}$	Real-Time Locational Marginal Price of Energy at a Steam Turbine	Real-time *energy market price* at steam turbine *delivery point* ‘s’ in *metering interval* ‘t’ of *settlement hour* ‘h’. **Unit of measurement:** $/MWh to the nearest cent **Time resolution**: interval
$RT\_ICP_h^{i,t}$	Real-Time Intertie Congestion Price	Real-time *ICP* for *energy* at *intertie metering point* ‘i’ in *metering interval* ‘t’ of *settlement hour* ’h’. **Unit of measurement:** $/MWh to the nearest cent **Time resolution:** interval

Variable	Name	Description
$RT\_PROR_{r,h}^{m,t}$	Real-Time Locational Marginal Price of Operating Reserve at a Delivery Point	Real-time *market price* of *class r reserve* at *delivery point* 'm' in *metering interval* 't' of *settlement hour* 'h'. Where: r1 = 10-minute spinning *operating reserve* r2 = 10-minute non-spinning *operating reserve* r3 = 30-minute *operating reserve* **Unit of measurement:** $/MWh to the nearest cent **Time resolution:** interval
$RT\_PROR_{r,h}^{i,t}$	Real-Time Locational Marginal Price of Operating Reserve at an Intertie Metering Point	Real-time *market price* of *class r reserve* at *intertie metering point* 'm' in *metering interval* 't' of *settlement hour* 'h'. Where: r1 = not applicable r2 = 10-minute non-spinning *operating reserve* r3 = 30-minute *operating reserve* **Unit of measurement:** $/MWh to the nearest cent **Time resolution:** interval
$RT\_PROR_{r,h}^{c,t}$	Real-Time Locational Marginal Price of Operating Reserve at a Combustion Turbine	Real-time *market price* of *class r reserve* at combustion turbine *delivery point* 'c' in *metering interval* 't' of *settlement hour* 'h'. Where: r1 = 10-minute spinning *operating reserve* r2 = 10-minute non-spinning *operating reserve* r3 = 30-minute *operating reserve* **Unit of measurement:** $/MW to the nearest cent **Time resolution:** interval
$RT\_PROR_{r,h}^{s,t}$	Real-Time Locational Marginal Price of Operating Reserve at a Steam Turbine	Real-time *market price* of *class r reserve* at steam turbine *delivery point* 's' in *metering interval* 't' of *settlement hour* 'h'. Where: r1 = 10-minute spinning *operating reserve* r2 = 10-minute non-spinning *operating reserve* r3 = 30-minute *operating reserve* **Unit of measurement:** $/MWh to the nearest cent **Time resolution:** interval

Variable	Name	Description
$ISPROR^{i,t}_{r,h}$	Intertie Settlement Price of Operating Reserve at an Intertie Metering Point	Real-time *market price* of *class r reserve* at *intertie metering point* ‘i’ in *metering interval* ‘t’ of *settlement hour* ‘h’. Where: r1 = not applicable r2 = 10-minute non-spinning *operating reserve* r3 = 30-minute *operating reserve* **Unit of measurement:** $/MWh to the nearest cent **Time resolution:** interval
$ISP^{i,t}_{h}$	Intertie Settlement Price of Energy at an Intertie Metering Point	Real-time *energy market price* at *intertie metering point* ‘i’ in *metering interval* ‘t’ of *settlement hour* ’h’. **Unit of measurement:** $/MWh to the nearest cent **Time resolution:** interval

Table 3-28 lists the schedules received from the RT calculation engine.

Table 3-28: Schedules Received from the RT Calculation Engine

Variable	Name	Description
$RT\_QSI^{m,t}_{k,h}$	Real-Time Quantity of Energy Scheduled for Injection at a Delivery Point	Real-time quantity of *energy* scheduled for injection by *market participant* ‘k’ at *delivery point* ‘m’ in *metering interval* ‘t’ of *settlement hour* ‘h’. **Unit of measurement:** MWh **Time resolution:** interval
$RT\_QSI^{c,t}_{k,h}$	Real-Time Quantity of Energy Scheduled for Injection at a Combustion Turbine	Real-time quantity of *energy* scheduled for injection by *market participant* ‘k’ at combustion turbine *delivery point* ‘c’ in *metering interval* ‘t’ of *settlement hour* ‘h’. **Unit of measurement:** MWh **Time resolution:** interval
$RT\_QSI^{s,t}_{k,h}$	Real-Time Quantity of Energy Scheduled for Injection at a Steam Turbine	Real-time quantity of *energy* scheduled for injection by *market participant* ‘k’ at steam turbine *delivery point* ‘c’ in *metering interval* ‘t’ of *settlement hour* ‘h’. **Unit of measurement:** MWh **Time resolution:** interval

Variable	Name	Description
$\text{RT\_QSW}_{k,h}^{m,t}$	Real-Time Quantity of Energy Scheduled for Withdrawal at a Delivery Point	Real-time quantity of *energy* scheduled for withdrawal by *market participant* 'k' at *delivery point* 'm' in *metering interval* 't' of *settlement hour* 'h'. **Unit of measurement:** MWh **Time resolution:** interval
$\text{RT\_QSOR}_{r,k,h}^{m,t}$	Real-Time Scheduled Quantity of Operating Reserve at a Delivery Point	Real-time scheduled quantity of *class r reserve* for *market participant* 'k' at *delivery point* 'm' in *metering interval* 't' of *settlement hour* 'h'. Where: r1 = 10-minute spinning *operating* reserve r2 = 10-minute non-spinning *operating reserve* r3 = 30-minute *operating reserve* **Unit of measurement:** MWh **Time resolution:** interval
$\text{RT\_QSOR}_{r,k,h}^{c,t}$	Real-Time Scheduled Quantity of Operating Reserve at a Combustion Turbine	Real-time scheduled quantity of *class r reserve* for *market participant* 'k' at combustion turbine *delivery point* 'c' in *metering interval* 't' of *settlement hour* 'h'. Where: r1 = 10-minute spinning *operating* reserve r2 = 10-minute non-spinning *operating reserve* r3 = 30-minute *operating reserve* **Unit of measurement:** MWh **Time resolution:** interval
$\text{RT\_QSOR}_{r,k,h}^{s,t}$	Real-Time Scheduled Quantity of Operating Reserve at a Steam Turbine	Real-time scheduled quantity of *class r reserve* for *market participant* 'k' at steam turbine *delivery point* 's' in *metering interval* 't' of *settlement hour* 'h'. Where: r1 = 10-minute spinning *operating* reserve r2 = 10-minute non-spinning *operating reserve* r3 = 30-minute *operating reserve* **Unit of measurement:** MWh **Time resolution:** interval

Variable	Name	Description
$RT\_QSOR_{r,k,h}^{i,t}$	Real-Time Scheduled Quantity of Operating Reserve at an Intertie Metering Point	Real-time scheduled quantity of *class r reserve* for *market participant* 'k' at *intertie metering point* 'i' in *metering interval* 't' of *settlement hour* 'h'. Where: r1 = not applicable r2 = 10-minute non-spinning *operating reserve* r3 = 30-minute *operating reserve* **Unit of measurement:** MWh **Time resolution:** interval
$SQEW_{k,h}^{i,t}$	Scheduled Quantity of Energy Withdrawn at an Intertie Metering Point	**Note: existing variable** Scheduled quantity, in MWh, of *energy* withdrawn by *market participant* 'k' at *intertie metering point* 'i' for each *metering interval* t' in *settlement hour* 'h'. **Unit of measurement:** MWh **Time resolution:** interval
$SQEI_{k,h}^{i,t}$	Scheduled Quantity of Energy Injected at an Intertie Metering Point	**Note: existing variable** Scheduled quantity, in MWh, of *energy* injected by *market participant* 'k' at *intertie metering point* 'i' for each *metering interval* t' in *settlement hour* 'h'. **Unit of measurement:** MWh **Time resolution:** interval

The RT calculation engine will perform ex-ante mitigation for economic withholding and produce conduct and price impact test results and mitigated *dispatch data* when such tests result in failure. See the Market Power Mitigation detailed design document for a description of these processes. The RT calculation engine will be the source of mitigated *dispatch data* and test results provided to the *settlement process* for potential *settlement* mitigation of make-whole payments and other guarantee payments.

Table 3-29 identifies the mitigation data provided by the RT calculation engine to the *settlement process* at a summary level.

Table 3-29: Mitigation Results from the RT Calculation Engine

Name	Description
Conduct Test Result	Pass or fail results of units at *delivery point* 'm' undergoing the conduct test for each *dispatch interval* 't' of *dispatch hour* 'h'.
Price Impact Test Result	Pass or fail results of units at *delivery point* 'm' undergoing the price impact test for each *dispatch interval* 't' of *dispatch hour* 'h'.

Name	Description
Mitigated Dispatch Data	Mitigated *dispatch data* enhanced to reflect the most restrictive failed *dispatch data* parameter during the interval, hour, or commitment period for the unit that failed the conduct test for *market participant* 'k' at *delivery point* 'm' for each *dispatch interval* 't', *dispatch hour* 'h' or commitment period. Potential mitigated financial *dispatch data* parameters includes: • *Energy offers* • *Operating reserve offers* • *Energy offers* for the range of production up to MLP
Resource Constrained Area Mitigation Test Conditions	Constrained area mitigation condition for each resource at *delivery point* 'm' prevailing during each *dispatch interval* 't' of *settlement hour* 'h'. The relevant impact threshold used in MWP impact testing for *market participant* 'k' will be applied depending on the constrained area condition under which the resource failed the conduct test. See Table 3-30: RT Thresholds from the Market Power Mitigation Information System.

Table 3-30 identifies the RT mitigation data provided by the Market Power Mitigation Information System to the *settlement process*.

Table 3-30: RT Thresholds from the Market Power Mitigation Information System

Name	Description
Make-Whole Payment Impact Test Thresholds	The relevant impact threshold used in MWP impact testing for *market participant* 'k' will be applied depending on the constrained area condition under which the resource failed the conduct test: • Broad constrained area (BCA) for *energy* • Narrow constrained area (NCA) for *energy* • Dynamic constrained area (DCA) for *energy* • *Reliability* constraint for *energy* • Global market power for *energy* • Global market power for *operating reserve* • Local market power for *operating reserve* Refer to the Market Power Mitigation detailed design, Table 3-3 for mitigation conditions for make-whole payment impact testing.

Table 3-31: Commitment Information from the RT Calculation Engine

Name	Description
Notice of Failure for PD Commitment	Notice of Failure information submitted by a resource that is unable to fulfill its PD commitment.

Table 3-32: Other Data Used for Settlement

Variable	Name	Description
$PB\_IM_{h}^{t}$	Price Bias Adjustment Factor for Import Transactions	**Note: existing variable** Price bias adjustment factor for import transactions in effect during *metering interval* 't' of *settlement hour* 'h'.
$PB\_EX_{h}^{t}$	Price Bias Adjustment Factor for Export Transactions	**Note: existing variable** Price bias adjustment factor for export transactions in effect during *metering interval* 't' of *settlement hour* 'h'
$RT\_ISD_{k,h}^{i,t}$	Real-time Import Scheduling Deviation	Real-time import scheduling deviation quantity calculated for *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h' .
$RT\_ESD_{k,h}^{i,t}$	Real-time Export Scheduling Deviation	Real-time export scheduling deviation quantity calculated for *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h'.

3.5.6.2 RT Offer and Bid Data

RT *offers* and *bids* will be specific to a generation or load resource and associated *delivery point* or to an import/export transaction specific to a *market participant* and *boundary entity* source/sink. Table 3-33 summarizes the attributes of these *offers* and *bids*.

Table 3-33: Financial Dispatch Data for Physical Transactions Submitted to the Real-Time Market

Variable	Name	Description
$BE_{k,h}^{m,t}$	Real-Time Energy Offer at a Delivery Point	A matrix of up to 20 *price-quantity pairs* offered by *market participant* 'k' to supply *energy* during *settlement hour* 'h'. *Energy offers* submitted in real-time, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *delivery point* 'm' during *metering interval* 't' of *settlement hour* 'h', arranged in ascending order by the offered price in each *price-quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2.

Variable	Name	Description
$BE_{k,h}^{i,t}$	Real-Time Energy Offer at an Intertie Metering Point	A matrix of up to 20 *price-quantity pairs* offered by *market participant* 'k' to supply *energy* during *settlement hour* 'h'. *Energy offers* submitted in real-time, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h', arranged in ascending order by the offered price in each *price-quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2.
$BE_{k,h}^{p,t}$	Real-Time Energy Offer at a Pseudo-Unit	A matrix of up to 20 *price-quantity pairs* offered by *market participant* 'k' to supply *energy* during *settlement hour* 'h'. *Energy offers* submitted in real-time, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *pseudo-unit* 'p' during *metering interval* 't' of *settlement hour* 'h', arranged in ascending order by the offered price in each *price-quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2.
$BE_{k,h}^{c,t}$	Real-Time Energy Offer at a Combustion Turbine	A matrix of up to 20 *price-quantity pairs* offered by *market participant* 'k' to supply *energy* during *settlement hour* 'h'. *Energy offers* submitted in real-time, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at combustion turbine *delivery point* 'c' during *metering interval* 't' of *settlement hour* 'h', arranged in ascending order by the offered price in each *price-quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2.
$BE_{k,h}^{s,t}$	Real-Time Energy Offer at a Steam Turbine	A matrix of up to 20 *price-quantity pairs* offered by *market participant* 'k' to supply *energy* during *settlement hour* 'h'. *Energy offers* submitted in real-time, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at steam turbine *delivery point* 's' during *metering interval* 't' of *settlement hour* 'h', arranged in ascending order by the offered price in each *price-quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2.

Variable	Name	Description
$BL_{k,h}^{m,t}$	Real-Time Energy Bid at a Delivery Point	A matrix of up to 20 *price-quantity pairs bid* by *market participant* 'k' to withdraw *energy* during *settlement hour* 'h'. *Energy bids* submitted in real-time, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *delivery point* 'm' during *metering interval* 't' of *settlement hour* 'h', arranged in ascending order by the offered price in each *price-quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2.
$BL_{k,h}^{i,t}$	Real-Time Energy Bid at an Intertie Metering Point	A matrix of up to 20 *price-quantity pairs bid* by *market participant* 'k' to withdraw *energy* during *settlement hour* 'h'. *Energy bids* submitted in real-time, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *intertie metering point* 'm' during *metering interval* 't' of *settlement hour* 'h', arranged in ascending order by the offered price in each *price-quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2.
$BOR_{r,k,h}^{m,t}$	Real-Time Operating Reserve Offer Submitted at a Delivery Point	**Available to dispatchable *registered facilities*.** A matrix of up to 5 *price-quantity pairs* offered by *market participant* 'k' to supply *class r reserve* during *metering interval* 't' of *settlement hour* 'h'. *Operating reserve offer* submitted in real-time, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *delivery point* 'm' during *metering interval* 't' of *settlement hour* 'h', arranged in ascending order by the offered price in each *price-quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2. Where: r1 = 10-minute spinning *operating reserve* r2 = 10-minute non-spinning *operating reserve* r3 = 30-minute *operating reserve*

Variable	Name	Description
$BOR^{i,t}_{r,k,h}$	Real-Time Operating Reserve Offer Submitted at an Intertie Metering Point	**Available to dispatchable *registered facilities*.** A matrix of up to 5 *price-quantity pairs* offered by *market participant* 'k' to supply *class r reserve* during *metering interval* 't' of *settlement hour* 'h'. *Operating reserve offer* submitted in real-time, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h', arranged in ascending order by the offered price in each *price-quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2. Where: r1 = Not applicable r2 = 10-minute non-spinning *operating reserve* r3 = 30-minute *operating reserve*
$BOR^{p,t}_{r,k,h}$	Real-Time Operating Reserve Offer Submitted at a Pseudo-Unit	**Available to dispatchable *registered facilities*.** A matrix of up to 5 *price-quantity pairs* offered by *market participant* 'k' to supply class 'r' *operating reserve* during *metering interval* 't' of *settlement hour* 'h'. *Operating reserve offer* submitted in real-time, represented as an N by 2 matrix of *price-quantity pairs* by *market participant* 'k' at *pseudo-unit* 'p' during *metering interval* 't' of *settlement hour* 'h', arranged in ascending order by the offered price in each *price-quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2. Where: r1 = 10-minute spinning *operating reserve* r2 = 10-minute non-spinning *operating reserve* r3 = 30-minute *operating reserve*
$RT\_GOG\_SU^{m}_{k,h}$	Real-Time Generator Offer Guarantee Start-Up Offer	**Available to eligible *generation facilities*.** Start-up offer associated with financial *offers* for the Real-Time Generator Offer Guarantee, for a given *settlement hour* 'h' at *delivery point* 'm' for *market participant* 'k' *per-start.* **Unit of measurement:** $ (dollar rounded to the nearest cent *per-start*)

3.5.6.3 Other RT Data

Measurement quantities specific to a generation or load resource and associated *delivery point* will continue to be received by the Meter Data Management System (MDMS). Table 3-34 summarizes the attributes of these measurement quantities.

Table 3-34: Revenue Metering Data Received from the Meter Data Management System

Variable	Name	Description
$AQEI_{k,h}^{c,t}$	Allocated Quantity of Energy Injected at a Combustion Turbine	Allocated quantity of energy injected by *market participant* ‘k’ at combustion turbine *RWM* ‘c’ in *metering interval* ‘t’ of *settlement hour* ‘h’. Where: **Unit of measurement:** MWh **Time resolution:** interval
$AQEI_{k,h}^{s,t}$	Allocated Quantity of Energy Injected at a Steam Turbine	Allocated quantity of energy injected by *market participant* ‘k’ at steam turbine *RWM* ‘s’ in *metering interval* ‘t’ of *settlement hour* ‘h’. Where: **Unit of measurement:** MWh **Time resolution:** interval
$AQEI_{k,h}^{m,t}$	Allocated Quantity of Energy Injected	**Note: existing variable** Allocated quantity of energy injected by *market participant* ‘k’ at *RWM* ‘m’ in *metering interval* ‘t’ of *settlement hour* ‘h’. Where: **Unit of measurement:** MWh **Time resolution:** interval
$AQEW_{k,h}^{m,t}$	Allocated Quantity of Energy Withdrawn	**Note: existing variable** Allocated quantity of energy withdrawn by *market participant* ‘k’ at *RWM* ‘m’ in *metering interval* ‘t’ of *settlement hour* ‘h’. Where: **Unit of measurement:** MWh **Time resolution:** interval

3.5.6.4 Settlement Input Values Derived from RT Data

The *settlement process* will need to derive the following new sets of data to be used in the *settlement* calculation:

- **Economic Operating Point:** In the real-time timeframe, the EOP indicates the optimum operating point of a *generation facility* or *dispatchable load* that is implied by the *real-time market price*. A generation or load *facility’s* EOP is a point on its *offer* or *bid* curve that is a function of the real-time LMP, the *generation facility* or *dispatchable load’s* real-time schedule/injection and real-time outage/ de-rate information. Section 3.7.5 describes the EOP in further detail in the context of the RT_MWP;

- **Facility-based *offers* for units modelled as PSUs:** As previously noted in Section 3.5.4, under MRP, PSU modelling will be available in all timeframes from DAM through to real-time. In the real-time timeframe, the real-time calculation engine will translate the PSU schedules into PU schedules and provide these to the *settlement process* before the *settlement* calculations take place; and
- **Load forecast deviation charge (LFDC)**: LFDC is the derived hourly province-wide forecast deviation dollar per megawatt hour ($/MWh) for the total cost of forecast deviation for *non-dispatchable loads*. The *IESO* will represent *non-dispatchable loads* as part of the hourly average NDL *demand* forecasts to be used by the calculation engines. Load forecast deviations may occur when the real-time load quantity of *energy* withdrawn differs from the quantity scheduled for *non-dispatchable loads*. When such deviations occur, there may be a cost impact. The calculation of LFDC is described in Section 3.6.3:Non-Dispatchable Load Settlement.

Table 3-35: Description of Settlement Input Values Derived from RT Data

Variable	Name	Description
$\mathrm{RT\_GOG\_DIPC}_{k,h}^{c,t}$	Real-Time Generator Offer Guarantee Derived Interval Price Curve at a Combustion Turbine	Real-time *energy* price curves derived from submitted 5-minute real-time PSU *energy offers*, for Real-Time Generator Offer Guarantee *settlement*, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at combustion turbine *delivery point* 'c' during *metering interval* 't' of *settlement hour* 'h', arranged in ascending order by the offered price in each *price-quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2. For intervals when the CT is operating in single cycle mode, this variable will be constructed using the associated PSU's pre-dispatch *energy offers* $\mathrm{PD\_BE}_{k,h}^{p,t}$ as they were submitted into the PD run that issued the operational constraint in that interval. For all other intervals, this variable will be constructed using the associated PSU's real-time *energy offers* $\mathrm{BE}_{k,h}^{p,t}$.

Variable	Name	Description
$RT\_GOG\_DIPC_{k,h}^{s,t}$	Real-Time Generator Offer Guarantee Derived Interval Price Curve at a Steam Turbine	Real-time *energy* price curves derived from submitted 5-minute real-time PSU *energy offers*, for Real-Time Generator Offer Guarantee *settlement*, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at steam turbine *delivery point* 's' during *metering interval* 't' of *settlement hour* 'h', arranged in ascending order by the offered price in each *price-quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2. It is constructed from the real-time *energy offers* for all PSUs that meet the eligibility requirements for inclusion in RT_GOG for that *metering interval* 't'. It will not include any *energy offers* from PSUs that operated in single cycle mode in that *metering interval* 't'.
$OR\_RT\_GOG\_DIPC_{r,k,h}^{c,t}$	Real-Time Generator Offer Guarantee Derived Interval Price Curve for Operating Reserve at a Combustion Turbine	Real-time *class r reserve* price curves derived from submitted 5-minute real-time PSU *class r reserve offers*, for Real-time Generator Offer Guarantee *settlement*, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at combustion turbine *delivery point* 'c' during *metering interval* 't' of *settlement hour* 'h', arranged in ascending order by the offered price in each *price-quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2. For intervals when the CT is operating in single cycle mode, this variable will be constructed using the associated PSU's pre-dispatch *operating reserve offers* $PD\_BOR_{r,k,h}^{p,t}$, as they were submitted into the PD run that issued the operational constraint in that interval. For all other intervals, this variable will be constructed using the associated PSU's real-time *operating reserve offers* $BOR_{r,k,h}^{p,t}$ Where: r1 = 10-minute spinning *operating reserve* r2 = 10-minute non-spinning *operating reserve* r3 = 30-minute *operating reserve*

Variable	Name	Description
$OR\_RT\_GOG\_DIPC^{s,t}_{r,k,h}$	Real-Time Generator Offer Guarantee Derived Interval Price Curve for Operating Reserve at a Steam Turbine	Real-time *class r reserve* price curves derived from submitted 5-minute real-time PSU *class r reserve offers*, for Real-Time Generator Offer Guarantee *settlement*, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at steam turbine *delivery point* 's' during *metering interval* 't' of *settlement hour* 'h', arranged in ascending order by the offered price in each *price-quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2. It is constructed from the real-time OR *offers* of all PSUs that meet the eligibility requirements for inclusion in RT_GOG for that *metering interval* 't'. It will not include any OR *offers* from PSUs that operated in single cycle mode in that *metering interval* 't' Where: r1 = 10-minute spinning *operating reserve* r2 = 10-minute non-spinning *operating reserve* r3 = 30-minute *operating reserve*
$RT\_GOG\_DIGQ^{s,t}_{k,h}$	Real-Time Generator Offer Guarantee Derived Interval Guaranteed Quantity at a Steam Turbine	Portion of the real-time quantity of *energy* scheduled for injection that is eligible for Real-Time Generator Offer Guarantee *settlement* for *market participant* 'k' at steam turbine *delivery point* 's' during *metering interval* 't' of *settlement hour* 'h'. This variable represents the portion of the ST RT_QSI that is eligible for inclusion in the RT_GOG.
$OR\_RT\_GOG\_DIGQ^{s,t}_{r,k,h}$	Real-Time Generator Offer Guarantee Derived Interval Guaranteed Quantity for Operating Reserve at a Steam Turbine	Portion of the real-time quantity of *class r reserve* schedule that is eligible for Real-Time Generator Offer Guarantee *settlement* for *market participant* 'k' at steam turbine *delivery point* 's' during *metering interval* 't' of *settlement hour* 'h'. This variable represents the portion of the ST's RT_QSOR that is eligible for inclusion in the RT_GOG. Where: r1 = 10-minute spinning *operating reserve* r2 = 10-minute non-spinning *operating reserve* r3 = 30-minute *operating reserve*

Variable	Name	Description
$RT\_MWP\_DIPC^{c,t}_{k,h}$	Real-Time Make-Whole Payment Derived Interval Price Curve at a Combustion Turbine	Real-time *energy* price curves derived from submitted 5-minute real-time PSU *energy offers*, for Real-Time Make-Whole Payment *settlement,* represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at combustion turbine *delivery point* 'c' during *metering interval* 't' of *settlement hour* 'h', arranged in ascending order by the offered price in each *price-quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2.
$RT\_MWP\_DIPC^{s,t}_{k,h}$	Real-Time Make-Whole Payment Derived Interval Price Curve at a Steam Turbine	Real-time *energy* price curves derived from submitted 5-minute real-time PSU *energy offers*, for Real-Time Make-Whole Payment *settlement,* represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at steam turbine *delivery point* 's' during *metering interval* 't' of *settlement hour* 'h', arranged in ascending order by the offered price in each *price-quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2.
$OR\_RT\_MWP\_DIPC^{c,t}_{r,k,h}$	Real-Time Make-Whole Payment Derived Interval Price Curve for Operating Reserve at a Combustion Turbine	Real-time *class r reserve* price curves derived from submitted 5-minute real-time PSU *class r reserve offers,* for Real-Time Make-Whole Payment *settlement*, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at combustion turbine *delivery point* 'c' during *metering interval* 't' of *settlement hour* 'h', arranged in ascending order by the offered price in each *price-quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2. Where: r1 = 10-minute spinning *operating reserve* r2 = 10-minute non-spinning *operating reserve* r3 = 30-minute *operating reserve*
$OR\_RT\_MWP\_DIPC^{s,t}_{r,k,h}$	Real-Time Make-Whole Payment Derived Interval Price Curve for Operating Reserve at a Steam Turbine	Real-time *class r reserve* price curves derived from submitted 5-minute real-time PSU *class r reserve offers,* for Real-Time Make-Whole Payment *settlement*, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at steam turbine *delivery point* 's' during *metering interval* 't' of *settlement hour* 'h', arranged in ascending order by the offered price in each *price-quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2. Where: r1 = 10-minute spinning *operating reserve* r2 = 10-minute non-spinning *operating reserve* r3 = 30-minute *operating reserve*

Variable	Name	Description
$RT\_QSI\_DIGQ_{k,h}^{s,t}$	Real-Time Quantity of Energy Scheduled for Injection Derived Interval Guaranteed Quantity for Injection at a Steam Turbine	Portion of the real-time quantity of *energy* scheduled for injection, derived from real-time PSU *energy* schedules for *market participant* 'k' at steam turbine *delivery point* 's' during *metering interval* 't' of *settlement hour* 'h'.
$RT\_LC\_EOP_{k,h}^{m,t}$	Real-Time Lost Cost Economic Operating Point at a Delivery Point	Real-Time lost cost economic operating point for *market participant* 'k' at *delivery point* 'm' during *metering interval* 't' of *settlement hour* 'h'.
$RT\_LC\_EOP_{k,h}^{i,t}$	Real-Time Lost Cost Economic Operating Point at an Intertie Metering Point	Real-time lost cost economic operating point for *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h'.
$RT\_LC\_EOP_{k,h}^{c,t}$	Real-Time Lost Cost Economic Operating Point at a Combustion Turbine	Real-time lost cost economic operating point for *market participant* 'k' at combustion turbine *delivery point* 'c' during *metering interval* 't' of *settlement hour* 'h'. It is the CT portion of the associated PSU's RT_LC_EOP, which is equal to the quantity at which the PSU_RT_LMP intersects the PSU's real-time *offer* curve.
$RT\_LC\_EOP_{k,h}^{s,t}$	Real-Time Lost Cost Economic Operating Point at a Steam Turbine	Real-time lost cost economic operating point for *market participant* 'k' at steam turbine *delivery point* 's' during *metering interval* 't' of *settlement hour* 'h'. It is the sum total of the ST portions of each associated PSU's RT_LC_EOP, which is equal to the quantity at which the PSU RT_LMP intersects the PSU's real-time *offer* curve.
$RT\_LOC\_EOP_{k,h}^{m,t}$	Real-Time Lost Opportunity Cost Economic Operating Point at a Delivery Point	Real-time lost opportunity cost economic operating point for *market participant* 'k' at *delivery point* 'm' during *metering interval* 't' of *settlement hour* 'h'.
$RT\_LOC\_EOP_{k,h}^{i,t}$	Real-Time Lost Opportunity Cost Economic Operating Point at an Intertie Metering Point	Real-time lost opportunity cost economic operating point for *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h'.

Variable	Name	Description
$RT\_LOC\_EOP_{k,h}^{c,t}$	Real-Time Lost Opportunity Cost Economic Operating Point at a Combustion Turbine	Real-time lost opportunity cost economic operating point for *market participant* 'k' at combustion turbine *delivery point* 'c' during *metering interval* 't' of *settlement hour* 'h'. It is the CT portion of the associated PSU's RT_LOC_EOP, which is defined as the profit-maximizing level of output for the PSU, determined through joint optimization across the *energy market* and *operating reserve market.*
$RT\_LOC\_EOP_{k,h}^{s,t}$	Real-Time Lost Opportunity Cost Economic Operating Point at a Steam Turbine	Real-time lost opportunity cost economic operating point for *market participant* 'k' at steam turbine *delivery point* 's' during *metering interval* 't' of *settlement hour* 'h'. It is the sum total of the ST portions of each associated PSU's RT_LOC_EOP, which is defined as the profit-maximizing level of output for the PSU, determined through joint-optimization across the *energy market* and *operating reserve market.*
$RT\_OR\_LC\_EOP_{r,k,h}^{m,t}$	Real-Time Lost Cost Economic Operating Point for Operating Reserve at a Delivery Point	Real-time lost cost economic operating point of *class r reserve* for *market participant* 'k' at *delivery point* 'm' during *metering interval* 't' of *settlement hour* 'h'. Where: r1 = 10-minute spinning *operating reserve* r2 = 10-minute non-spinning *operating reserve* r3 = 30-minute *operating reserve*
$RT\_OR\_LC\_EOP_{r,k,h}^{i,t}$	Real-Time Lost Cost Economic Operating Point for Operating Reserve at an Intertie Metering Point	Real-time lost cost economic operating point of *class r reserve* for *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h'. Where: r1 = not applicable r2 = 10-minute non-spinning *operating reserve* r3 = 30-minute *operating reserve*

Variable	Name	Description
$RT\_OR\_LC\_EOP^{c,t}_{r,k,h}$	Real-Time Lost Cost Economic Operating Point for Operating Reserve at a Combustion Turbine	Real-time lost cost economic operating point of *class r reserve* for *market participant* 'k' at combustion turbine *delivery point* 'c' during *metering interval* 't' of *settlement hour* 'h'. It is the CT portion of the associated PSU's RT_OR_LC_EOP, which is equal to the quantity at which the RT_PROR for *class r reserve* at PSU *delivery point* 'p' intersects the PSU's real-time *offer* curve for *class r reserve*. Where: r1 = 10-minute spinning *operating reserve* r2 = 10-minute non-spinning *operating reserve* r3 = 30-minute *operating reserve*
$RT\_OR\_LC\_EOP^{s,t}_{r,k,h}$	Real-Time Lost Cost Economic Operating Point for Operating Reserve at a Steam Turbine	Real-time lost cost economic operating point of *class r reserve* for *market participant* 'k' at steam turbine *delivery point* 's' during *metering interval* 't' of *settlement hour* 'h'. It is the sum total of the ST portions of each associated PSU's RT_OR_LC_EOP, which is equal to the quantity at which the RT_PROR for *class r reserve* at PSU *delivery point* 'p' intersects the PSU's real-time *offer* curve for *class r reserve.* Where: r1 = 10-minute spinning *operating reserve* r2 = 10-minute non-spinning *operating reserve* r3 = 30-minute *operating reserve*
$RT\_OR\_LOC\_EOP^{m,t}_{r,k,h}$	Real-Time Lost Opportunity Cost Economic Operating Point for Operating Reserve at a Delivery Point	Real-time lost opportunity cost economic operating point for *class r reserve* for *market participant* 'k' at *delivery point* 'm' during *metering interval* 't' of *settlement hour* 'h'. Where: r1 = 10-minute spinning *operating reserve* r2 = 10-minute non-spinning *operating reserve* r3 = 30-minute *operating reserve*
$RT\_OR\_LOC\_EOP^{i,t}_{r,k,h}$	Real-Time Lost Opportunity Cost Economic Operating Point for Operating Reserve at an Intertie Metering Point	Real-time lost opportunity cost economic operating point for *class r reserve* for *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h'. Where: r1 = 10-minute spinning *operating reserve* r2 = 10-minute non-spinning *operating reserve* r3 = 30-minute *operating reserve*

Variable	Name	Description
$RT\_OR\_LOC\_EOP^{c,t}_{r,k,h}$	Real-Time Lost Opportunity Cost Economic Operating Point for Operating Reserve at a Combustion Turbine	Real-time lost opportunity cost economic operating point for *class r reserve* for *market participant* 'k' at combustion turbine *delivery point* 'c' during *metering interval* 't' of *settlement hour* 'h'. It is the CT portion of the associated PSU's RT_OR_LOC_EOP, which is defined as the profit-maximizing level of *class r reserve* for the PSU, determined through joint-optimization across the *energy market* and *operating reserve market.* Where: r1 = 10-minute spinning *operating reserve* r2 = 10-minute non-spinning *operating reserve* r3 = 30-minute *operating reserve*
$RT\_OR\_LOC\_EOP^{s,t}_{r,k,h}$	Real-Time Lost Opportunity Cost Economic Operating Point for Operating Reserve at a Steam Turbine	Real-time lost opportunity cost economic operating point for *class r reserve* for *market participant* 'k' at steam turbine *delivery point* 's' during *metering interval* 't' of *settlement hour* 'h'. It is the sum total of the ST portions of each associated PSU's RT_OR_LOC_EOP, which is defined as the profit-maximizing level of *class r reserve* for the PSU, determined through joint optimization across the *energy market* and *operating reserve market.* Where: r1 = 10-minute spinning *operating reserve* r2 = 10-minute non-spinning *operating reserve* r3 = 30-minute *operating reserve*
$RT\_STP\_QSI^{p,t}_{k,h}$	Real-Time Steam Turbine Portion Derived Quantity of Energy Scheduled for Injection at a Pseudo-Unit	Real-time steam turbine portion of the derived quantity of *energy* scheduled for injection by *market participant* 'k' at *pseudo-unit* 'p' in *metering interval* 't' of *settlement hour* 'h'. **Unit of measurement:** MWh **Time resolution:** interval

3.5.6.5 RT PBC Data

The *real-time market physical bilateral contract data* (RT PBC data) will continue to be collected and used in the future market. Table 3-36 lists the existing variables that will continue to be used, with minor modifications to the Reallocate Quantity, which will take into consideration any applicable DAM PBC quantities.

Table 3-36: RT PBC Quantities Collected by the Settlement Process

Variable	Name	Description
$\mathrm{BCQ}_{s,k,h}^{m,t}$	Physical Bilateral Contract Quantity of Energy Bought at a Delivery Point	*Physical bilateral contract quantity* of *energy* in MWh bought by *buying market participant* 'k' from *selling market participant* 's' at *delivery point* 'm' for each *metering interval* 't' in *settlement hour* 'h'. **Unit of measurement:** MWh **Time resolution:** interval
$\mathrm{BCQ}_{k,b,h}^{m,t}$	Physical Bilateral Contract Quantity of Energy Sold at a Delivery Point	*Physical bilateral contract quantity* of *energy* in MWh sold by *selling market participant* 'k' to *buying market participant* 'b' at *delivery point* 'm' for each *metering interval* 't' in *settlement hour* 'h'. **Unit of measurement:** MWh **Time resolution:** interval
$\mathrm{BCQ}_{s,k,h}^{i,t}$	Physical Bilateral Contract Quantity of Energy Bought at an Intertie Metering Point	*Physical bilateral contract quantity* of *energy* in MWh bought by *buying market participant* 'k' from *selling market participant* 's' at *intertie metering point* 'i' for each *metering interval* 't' in *settlement hour* 'h'. **Unit of measurement:** MWh **Time resolution:** interval
$\mathrm{BCQ}_{k,b,h}^{i,t}$	Physical Bilateral Contract Quantity of Energy Sold at Intertie Metering Point	*Physical bilateral contract quantity* of *energy* in MWh sold by *selling market participant* 'k' to *buying market participant* 'b' at *intertie metering point* 'i' for each *metering interval* 't' in *settlement hour* 'h'. **Unit of measurement:** MWh **Time resolution:** interval

Variable	Name	Description
$RQ_{k,h}^{m,i,t}$	Reallocate Quantity	A quantity derived from a *physical bilateral contract quantity* in order to reallocate a component of *hourly uplift* from the *buying market participant* to the *selling market participant* in direct proportion to the size of the *physical bilateral contract.* This is the net sum of any applicable DAM and RT PBC Reallocate Quantities at *delivery point* 'm' and *intertie metering point* 'i' during *settlement hour* 'h' as indicated in all relevant *physical bilateral contract data* in which the transfer of this *hourly uplift settlement amount* has been agreed to between the *selling market participant* and the *buying market participant*. $RQ_{k,h}^{m,i,t} = \left[\sum_{B} \frac{DAM\_BCQ_{k,b,h}^{m,i}}{12} - \sum_{S} \frac{DAM\_BCQ_{s,k,h}^{m,i}}{12} + \sum_{B} BCQ_{k,b,h}^{m,i,t} - \sum_{S} BCQ_{s,k,h}^{m,i,t}\right]$

3.5.7 Collection of Market Integration Data

Between the time that the day-ahead market clears and the *real-time market* begins, various actions may take place that affect a *market participant's* performance relative to commitments made in the DAM and pre-dispatch timeframes. Of particular interest to the *settlement process* are events that affect the calculation of the DAM Make-Whole Payment (DAM_MWP), the Generation Offer Guarantee (GOG), the Real-Time Make-Whole Payment (RT_MWP) and Real-Time Intertie Offer Guarantee (RT_IOG). These detailed calculations are discussed in Section 3.7 of this document.

To derive the correct *settlement* outcomes for *market participants*, the *settlement process* needs to take into account the reasons why a given resource or import/export transaction that was scheduled in the DAM or committed in pre-dispatch deviated from its DAM schedule or PD commitment in the *real-time market*. Depending on the reasons, the *market participant* may or may not be entitled to a DAM_MWP, DAM_GOG, RT_GOG, RT_MWP or RT_IOG. This is particularly relevant in situations where the *facility* is subject to operational constraints, in which case the *settlement amount* may need to be adjusted. In other situations, a *facility* may be ineligible for payments. When a *facility* with a DAM financially binding schedule is dispatched down, the *IESO* will adjust the first *settlement* and second *settlement* accordingly.

The *IESO* may apply a 'reason code' when it manually alters an import or export schedule. New *intertie* reason codes will be required in the future market. The list of these new *intertie* reason codes and the resulting settlement treatment can be found in Section 3.7, Table 3-54.

3.5.8 Collection of Ex-Post Data

3.5.8.1 Market Failures and Errors

The *IESO* is responsible for maintaining appropriate market controls to address major risks to the operability of the *IESO-administered markets*. A market failure is one key risk, which occurs when one of the DAM, PD, or RT calculation engine runs experiences an interruption. Errors in *market prices* and/or schedules may also be identified.

The *IESO* will continue to resolve data inconsistencies that can result from market failures or other issues prior to settling *market participants*. The *settlement process* must be informed of all calculation engine failures and errors to ensure *settlement amounts* are calculated correctly.

See Section 3.8: Market Remediation for details and the Grid and Market Operations Integration detailed design document for further information.

3.5.8.2 Administrative Pricing

Administrative pricing is a market remediation method that the *IESO* can apply to resolve incorrect or missing prices in the *real-time market*. The *settlement process* will continue to be informed when an *administrative pricing* event occurs in the ex-post timeframe. In the future, the *administrative pricing* event will continue to be applicable to the *real-time market* only, consistent with today.

For more details, see Section 3.8 - Market Remediation and the Grid and Market Operations Integration detailed design document for further information.

3.5.9 Pseudo-Unit (PSU) Settlement Data

In the current market, the *IESO* models physical resource unit relationships through *pseudo-units* (PSU) in the day-ahead scheduling timeframe only. In the future market, *pseudo-unit* modelling will be implemented in all timeframes, DAM through to real-time.

In the current market, *market participants* can elect to offer both *energy* and *operating reserve* on a PSU basis or as individual physical CT and ST units in DACP. In the future market, this option will still be available. If *market participants* have elected to operate their units as PSUs, they will *offer* into the market on a PSU basis only. PSU *offers* into the DAM will be carried forward in PD and RT and can be revised within applicable *offer* revision timelines.

Generation facilities that have opted to be scheduled as *pseudo-units* will be scheduled consistently through all timeframes on that basis. However, the actual *settlement amount* will be based on the physical unit (PU). To calculate *settlement amounts*, PU *offers* will continue to be derived from PSU *offers* in a manner consistent with the existing methodology, under each of the timeframes:

- The Derived Internal Price Curve (DIPC) derives the implied CT and ST PU offer curve by decomposing PSU offers based on PU relationships; and
- The Derived Interval Guarantee Quantity (DIGQ) will continue to be the portion of the ST schedule eligible for cost recovery.

3.5.9.1 Energy Market

The CT and ST PU *offer* curve constructed by DIPC will establish the cost side of providing *energy*, which is compared to the market revenues for the PU in order to calculate any payment for each PU.

The DIGQ will continue to be the portion of the ST schedule eligible for cost recovery. DIGQ will be the sum of the ST portion of the PSU schedules from all PSUs where the associated CT is eligible for the MWP/guarantee in question. The ST portion is described in Table 3-37 later in this section.

These formulations will allow comparison of all as-offered costs against actual revenues in the *energy market* for the PU.

3.5.9.2 Operating Reserve Market

Implied PU *operating reserve offers* will be derived from PSU *operating reserve offers* across all timeframes.

In order to determine as-offered *operating reserve* costs on a PU basis, the PSU model will construct an *operating reserve offer* DIPC for each class of reserve in a manner that is similar to the *energy offer* DIPC. The difference from the *energy offer* DIPC is due to the fact that *operating reserve offers*, unlike *energy offers*, are not tied to any particular output level or operating region. *Operating reserve offer* curves may have different underlying CT:ST shares depending on the schedules for *energy* and other classes of OR, and this will be taken into account. Except when curtailed to respect maximum capacities, the PSU *offer* curves will not change based on *energy* and *operating reserve* scheduling. However, the resulting CT and ST DIPCs will depend on which operating regions the *operating reserve offer* curves occupy.

A PSU must be committed to at least MLP in order for any *operating reserve* to be scheduled. Therefore, the *operating reserve offer* curves only occupy the dispatchable and duct-firing regions. Since there will be PSU modelling in all timeframes, it will be necessary to derive PU *operating reserve offer* curves from the PSU *operating reserve offer* curve for any calculation that requires PU OR *offer* curves.

3.5.9.3 Derived Data – ST_Portion

On a daily basis, *dispatch data* and registration data is used to derive the ST portion, and this data is provided as an input for *settlement* calculations. ST_Portion refers to the steam turbine MLP region (d1), dispatchable region (d2) and duct firing region (d3). As noted in the Offers, Bids and Data Inputs detailed design document, ST_Portion d1 is known as the ST Portion of the Lower Operating Region Amount (ST_OR_1). In this case, "OR" means Operating Region. ST_Portion d2 is the Middle Operating Region Amount (ST_OR_2) and ST_Portion d3 is the Upper Operating Region Amount (ST_OR_3).

Table 3-37: Derived Data for Pseudo-Units

Variable	Name	Description
$\text{ST\_Portion}^{p}_{k,d}$	Steam Turbine Portion of Energy	Steam turbine portion, representing the percent of the *pseudo-unit energy* that belongs to the ST for *market participant* 'k' at PSU 'p' in operating region 'd'. Where: d1 = MLP region d2 = Dispatchable region d3 = Duct Firing region **Unit of measurement:** %

Energy offers, start-up offers and speed no-load offers submitted by *market participants* for *pseudo-units* and other PSU derived inputs used in the *settlement* calculations are discussed in each of the applicable timeframes within Section 3.5 – Collection of Settlement-Ready Data.

3.6 Day-Ahead and Real-Time Energy and Operating Reserve Settlement

As introduced in Section 3.3.1, the *settlement* of the day-ahead market and *real-time market* for *energy* and *operating reserve* will be based upon first *settlement* and second *settlement*:

- **First *settlement*** includes *settlement amounts* for *energy* and *operating reserve* that can be completely calculated on the basis of *settlement* data from the DAM calculation engine.
- **Second *settlement*** includes the *settlement amounts* that can be calculated on the basis of *settlement* data from the DAM calculation engine reconciled with the *real-time market* results.

The *settlement* amounts for virtual transactions and the *settlement* amounts for physical transactions under the first and second *settlement* will be provided to *market participants* via *preliminary settlement statements* and *final settlement statements* issued 10 and 20 *business days* after the real-time *trading day*, respectively. *Settlement amounts* are not financial obligations until such time as they are reported on a *settlement statement*. Once reported on a *settlement statement*, the *market participant* may utilize the NoD process. All calculations reported on a *preliminary settlement statement* may be subject to the NoD process.

Settlement amounts resulting from the first and second *settlement* will maintain the necessary financial neutrality of the *IESO* as required under the *market rules*. This is described in greater detail in Section 3.9: Financial Neutrality.

Settlement amounts presented in this section are illustrated from a financial standpoint only. The final form of their presentation on *settlement statements* may vary from the descriptions provided in this document.

3.6.1 DA and RT Energy and OR Settlement: First Settlement

The first *settlement* is produced at the first stage in the two-*settlement* system. The *settlement amounts* calculated as part of first *settlement* are those amounts that can be calculated on the basis of the *settlement* data from the DAM calculation engine.

Table 3-38 summarizes the *settlement* amounts that will be calculated as part of the first *settlement* of the two-*settlement* system.

Table 3-38: Settlement Amounts in the First Settlement

Name	Acronym
Hourly Physical Transaction Settlement Amount[1]	HPTSA{1}
Hourly Virtual Transaction Settlement Amount	HVTSA{1}
Hourly Operating Reserve Settlement Amount	HORSA{1}

[1] includes the *settlement* of DAM and real-time *physical bilateral contracts*.

3.6.1.1 First Settlement Calculation: Hourly Physical Transaction Settlement Amount (HPTSA{1})

The first *settlement* of the Hourly Physical Transaction Settlement Amount (HPTSA{1}) will establish a *market participant's* position for *energy* in the DAM, net of any associated PBCs in the DAM.

As described earlier, the combined first and second *settlement* and the NDL *settlement* of the HPTSA will replace the current NEMSC used to settle *energy* positions in the *real-time market*. Although NEMSC and HPTSA are similar in nature in that they both settle *energy* positions, NEMSC is only used to settle *energy* positions in the *real-time market.* With the introduction of the day-ahead market, new *settlement amounts* are required that would settle *energy* positions in both the day-ahead market and the *real-time market*. This reflects a seamless transition within the *settlement process* into the future market, and provides transparency to m*arket participants* where there will be a period of time where *market participants* will continue to see NEMSC on their *settlement statements.* This will have no financial impact on *market participants* continuing to participate only in the *real-time market.*

The specific formula for calculating the *first settlement* HPTSA{1} has two variants and includes PBCs, depending on the nature of the *facility* or the transaction involved.

Table 3-39 provides the resolution details of the HPTSA{1} calculation.

Table 3-39: Resolution of HPTSA{1} Calculation

Attribute	Resolution
First *settlement* time resolution	Hourly
Geographic resolution	*Facilities* within Ontario: • By *delivery point* *Intertie* transactions: • By *intertie metering point*
DAM price accuracy	$/MWh to the nearest cent
DAM *energy* quantities	MW schedule values converted to MWh values for the purposes of *settlement* to the nearest 0.1 MWh
PBC quantities	MWh to the nearest 0.1 MWh

Table 3-40 describes the eligibility to receive first *settlement* under HPTSA on the basis of the type of *facility* or the transaction involved and the variant of the general HPTSA formula to be employed.

Table 3-40: Eligibility for HPTSA in First Settlement

Facility/Transaction Type	Eligible?	Special Processing Requirements
Quick start facility	Yes	Use formula variant 1
Non-dispatchable *generation facility*	Yes	Use formula variant 1
Boundary entity (imports & exports)	Yes	Use formula variant 1
Price responsive load	Yes	Use formula variant 2
Dispatchable load	Yes	Use formula variant 1
NQS *generation facility*	Yes	Use formula variant 1

The first *settlement* HPTSA{1}$_{k,h}$ for a given *market participant* ‘k’ in a given *settlement hour* ‘h’ is the sum of the PBC and variants as illustrated by the following formula:

$$HPTSA\{1\}_{k,h} = HPTSA\_PBC\{1\}_{k,h} + HPTSA\{1\}\_V1_{k,h} + HPTSA\{1\}\_V2_{k,h}$$

$$= \{\text{PBC}\} + \{\text{variant 1}\} + \{\text{variant 2}\}$$

First Settlement HPTSA – PBC

DAM PBCs are available to DAM *market participants* conducting physical transactions, regardless of the transaction sub-type.

PBCs under the HPTSA will be adjusted between first and second *settlement* to prevent counting the same PBC quantities twice for variants of the HPTSA formula. This treatment allows real-time PBCs to be factored into the HPTSA position without impacting the way real-time PBCs should be treated once the NEMSC is replaced with the HPTSA.

During first *settlement*, the HPTSA_PBC will consist of all the quantities bought and sold by the *market participant* valued at the applicable DAM zonal or nodal market price.

The formulation of HPTSA_PBC is as follows:

$$HPTSA\_PBC\{1\}_{k,h} = \sum^{M}\left[\left(DAM\_LMP_h^m\ x\ \left(\sum_S DAM\_BCQ_{s,k,h}^m - \sum_B DAM\_BCQ_{k,b,h}^m\right)\right) + \left(DAM\_LMP_h^i\ x\ \left(\sum_S DAM\_BCQ_{s,k,h}^i - \sum_B DAM\_BCQ_{k,b,h}^i\right)\right)\right]$$

Where:

‘M’	is the set of all *delivery points* ‘m’ and *intertie metering points* ‘i’.
‘S’	is the set of all *selling market participants* ‘s’.
‘B’	is the set of all *buying market participants* ‘b’.

First Settlement HPTSA – Formula Variant 1

The first *settlement* calculation of the HPTSA is common to *generation facilities*, import transactions, export transactions and all *load facilities* except *non-dispatchable loads* that have a financially binding DAM schedule generated by the DAM calculation engine.

This variant will not utilize the DAM *physical bilateral contract quantities* in order to prevent counting such quantities twice. In the event that a *market participant* has a DAM PBC, the *physical bilateral contract quantities* will be accounted for separately in the PBC under the previously described formulation.

The formulation of HPTSA{1}_V1 is as follows:

$$HPTSA\{1\}\_V1_{k,h} = \sum^{M}\left[\left(DAM\_QSI_{k,h}^m - DAM\_QSW_{k,h}^m\right) \times DAM\_LMP_h^m\right] + \left[\ (DAM\_QSI_{k,h}^i - DAM\_QSW_{k,h}^i)\ \times DAM\_LMP_h^i\right]$$

Where:

'M'	is the set of all *delivery points* associated with all dispatchable and non-dispatchable *generation facilities* and *dispatchable load facility delivery points* 'm' and *intertie metering points* 'i'.

First Settlement HPTSA – Formula Variant 2

This variant will apply specifically to price responsive loads. This includes price responsive loads that are scheduled by the DAM calculation engine to withdraw energy and physical *hourly demand response* resources that are registered as a price responsive load to fulfil a physical *demand response capacity obligation.* The DAM financially binding schedules for the physical *hourly demand response* resource and the price responsive load will be combined to calculate the first *settlement* amount for the price responsive load.

The formulation of HPTSA{1}_V2 is as follows:

$$HPTSA\{1\}\_V2_{k,h} = \sum^{M1}[(DAM\_QSW^{m}_{k,h} \times DAM\_LMP^{m}_{h}] + \sum^{M2}[(DAM\_QSW^{m}_{k,h} \times DAM\_LMP^{m}_{h}]$$

Where:

'M1'	is the set of all *delivery points* 'm' for price responsive loads.
'M2'	is the set of all *delivery points* 'm' for price responsive loads used as physical *hourly demand response* resource to fulfil *demand response capacity obligations.*

3.6.1.2 First Settlement Calculation: Hourly Virtual Transaction Settlement Amount (HVTSA{1})

The first *settlement* calculation of the Hourly Virtual Transaction Settlement Amount (HVTSA) will establish a *market participant's* position for *energy* in the day-ahead market with respect to virtual transactions. The *settlement* of virtual transactions will be based on the financially binding DAM schedules from the DAM calculation engine. 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*.

Table 3-41 provides the resolution details of the HVTSA{1} calculation.

Table 3-41: Resolution of HVTSA{1} Calculation

Attribute	Resolution
First *settlement* time resolution	Hourly
Geographic resolution	Virtual transaction zonal trading entity
DAM price accuracy	$/MWh to the nearest cent
DAM *energy* quantities (virtual)	MW schedule values converted to MWh values for the purposes of *settlement* to the nearest 0.1 MWh

Table 3-42 describes the eligibility to receive the first *settlement* HVTSA{1} on the basis of the type of *facility* or transaction involved.

Table 3-42: Eligibility for HVTSA in First Settlement

Facility/Transaction Type	Eligible?	Special Processing Requirements
Dispatchable *generation facility*	No	Not applicable
Non-dispatchable *generation facility*	No	Not applicable
Boundary entity (imports & exports)	No	Not applicable
Price responsive load	No	Not applicable
Dispatchable load	No	Not applicable
Virtual transaction to buy *energy*	Yes	Same formula used for both forms of virtual transactions
Virtual transaction to sell *energy*	Yes	

First Settlement HVTSA Formula

$$HVTSA\{1\}_{k,h} = \sum^{V} (DAM\_QVSI^{v}_{k,h} - DAM\_QVSW^{v}_{k,h}) \times DAM\_LMP^{v}_{h}$$

Where:

'V' is the set of all virtual transaction zonal trading entities 'v'.

3.6.1.3 First Settlement Calculation: Hourly Operating Reserve Settlement Amount (HORSA{1})

This section describes the first *settlement* calculation of the Hourly Operating Reserve Settlement Amount (HORSA{1}).

Offers to supply *class r operating reserve* in the DAM will be subject to the following conditions:

- *Market participants* in the day-ahead market will not be able to submit virtual *offers* for *operating reserve*; and
- All *market participants* that are able to offer *operating reserve* in the *real-time market* will be able to offer the same classes of *operating reserve* in the DAM.

Therefore, the *settlement* of *operating reserve* is confined to physical transactions.

The combined first and second *settlement* of the HORSA will completely replace the current Operating Reserve Settlement Credit (ORSC) used to settle *operating reserve* positions in the *real-time market*. New *settlement amounts* will be required that would settle *operating reserve* positions in both the DAM and *real-time market* with the introduction of DAM. This reflects a seamless transition within the *settlement process* into the future market, and provides transparency to *market participants* where there will be a period of time where *market participants* will continue to see ORSC on their *settlement statements*. This will have no financial impact on *market participants* continuing to participate only in the *real-time market.*

The *settlement* of physical transactions to sell *operating reserve* in the DAM will be identical to the first or second *settlement* division for the *settlement* of physical transactions for *energy*. This will help maintain consistency across the *settlement* of physical transactions in general.

Table 3-43 provides the resolution details of the HORSA{1} calculation.

Table 3-43: Resolution of HORSA{1} Calculation

Attribute	Resolution

First *settlement* time resolution	Hourly
Geographic resolution	*Facilities* within Ontario: • By *delivery point* *Intertie* transactions: • By *intertie* metering point
DAM price accuracy	$/MWh to the nearest cent
DAM class 'r' *operating reserve* quantities	MW schedule values converted to MWh values for the purposes of *settlement* to the nearest 0.1 MWh

Table 3-44 describes the eligibility to receive the first *settlement* of HORSA on the basis of the type of *facility* or transaction involved, and the variant of the general HORSA formula to be employed.

Table 3-44: Eligibility for HORSA in First Settlement

Facility/Transaction Type	Eligible?	Special Processing Requirements
Quick start facility	Yes	Use formula variant 1
Non-dispatchable *generation facility*	No	Not applicable
Boundary entity (imports & exports)	Yes	Use formula variant 1
Price responsive load	No	Not applicable
Dispatchable load	Yes	Use formula variant 1
NQS *generation facility*	Yes	Use formula variant 1

First Settlement HORSA - Formula Variant 1

Variant 1 of the HORSA *first settlement* formula will be common to all eligible physical transactions. The formulation is as follows:

$$HORSA\{1\}_{k,h} = \sum_{R}^{M} \left(DAM\_PROR^{m}_{r,h} \times DAM\_QSOR^{m}_{r,k,h} + DAM\_PROR^{i}_{r,h} \times DAM\_QSOR^{i}_{r,k,h}\right)$$

Where:

'M' is the set of all *delivery points* 'm' and *intertie metering points* 'i'

'R' is the set of each class r of *operating reserve*.

3.6.2 DA and RT Energy and OR Settlement: Second Settlement

The second *settlement* is produced at the second stage in the two-*settlement* system. It will balance any deviations that occur between the day-ahead market and the *real-time market*.

The second *settlement* will reconcile the *market participant's* position in the day-ahead market with the *real-time market* results. Table 3-45 summarizes the various *settlement amounts* that are calculated as part of the second *settlement*.

Table 3-45: Settlement Amounts in the Second Settlement

Name	Acronym
Hourly Physical Transaction Settlement Amount	HPTSA{2}
Hourly Virtual Transaction Settlement Amount	HVTSA {2}
Hourly Operating Reserve Settlement Amount	HORSA{2}
DAM Operating Reserve Uplift	DORU

3.6.2.1 Second Settlement Calculation: Hourly Physical Transaction Settlement Amount (HPTSA {2})

The second *settlement* calculation of the Hourly Physical Transaction Settlement Amount (HPTSA{2}) reconciles the differences between a *market participant's* position for *energy* in the day-ahead market, their actual *real-time market* activity and any associated PBCs in the day-ahead market or the *real-time market.*

The first and second *settlement* are matched to the same *facility* or *intertie* transaction, which will result in an HPTSA to a level of granularity described in the next sub-section.

Depending on the *facility* or transaction type involved, the specific formula for calculating the second *settlement* HPTSA{2} has two possible variants and PBC.

Table 3-46: Resolution of HPTSA{2}

Attribute	Resolution
Second *settlement* time resolution	Hourly Includes hourly aggregation of 5-minute quantities of allocated *energy* injections and withdrawals Includes hourly aggregation of 5-minute quantities for *physical bilateral contract quantities*
Geographic resolution	*Facilities* within Ontario: • By *delivery point* *Intertie* transactions: • By *intertie metering point*
DAM price accuracy	$/MWh to the nearest cent
DAM *energy* quantities	MW schedule values converted to MWh values for the purposes of *settlement* to the nearest 0.1 MWh
PBC quantities	MWh to the nearest 0.1 MWh
RT price accuracy	$/MWh to the nearest cent
All *real-time market settlement* data	• Real-time *metering data* at the *delivery points* to the nearest 0.001 MWh • *Real-time schedule* data at the *delivery points or intertie metering points* to the nearest 0.1 MWh

Table 3-47 describes the eligibility to receive the second *settlement* HPTSA{2} on the basis of the type of *facility* or transaction involved, and the variant of the general HPTSA{2} formula to be employed.

Table 3-47: Eligibility for HPTSA in Second Settlement

Facility/Transaction Type	Eligible?	Special Processing Requirements
Quick start facility	Yes	Use formula variant 1
Non-dispatchable *generation facility*	Yes	Use formula variant 1
Boundary entity (imports & exports)	Yes	Use formula variant 1
Price responsive load	Yes	Use formula variant 2
Dispatchable load	Yes	Use formula variant 1
NQS *generation facility*	Yes	Use formula variant 1

The second *settlement* $HPTSA\{2\}_{k,h}$ for a given *market participant* 'k' in a given *settlement hour* 'h' is the sum of the PBC and each variant of the formula. Therefore:

$$HPTSA\{2\}_{k,h} = HPTSA\_PBC\{2\}_{k,h} + HPTSA\{2\}\_V1_{k,h} + HPTSA\{2\}\_V2_{k,h}$$

$$= \quad \{\text{PBC}\} \quad + \quad \{\text{variant 1}\} \quad + \quad \{\text{variant 2}\}$$

Second Settlement HPTSA – PBC

DAM PBCs may be utilized by DAM *market participants* conducting physical transactions, regardless of the type of transaction.

PBCs under the HPTSA will be adjusted between first *settlement* and second *settlement* in order to avoid counting the same PBC quantities twice for variants of the HPTSA formula. This treatment will allow real-time PBCs to be factored into the HPTSA position without disturbing the way real-time PBCs should be treated after the NEMSC is replaced with the HPTSA.

During first *settlement*, the HPTSA_PBC consists of all DAM PBC quantities bought and sold by the *market participant* valued at the applicable DAM price.

During second *settlement*, the HPTSA_PBC consists of all *real-time market* PBC quantities valued at the applicable nodal *market price*. This *settlement amount* forms a part of the *market participant's* overall exposure to the HPTSA.

The formulation of the HPTSA_PBC during second *settlement* is as follows:

$HPTSA\_PBC\{2\}_{k,h}$ = [second *settlement* balancing amount for non-dispatchable and dispatchable *delivery points* and *intertie metering points*]

$HPTSA\_PBC\{2\}_{k,h}$ =

$$\sum^{M}\left[\sum^{T} RT\_LMP_h^{m,t}\ x\left(\sum_{S} BCQ_{s,k,h}^{m,t} - \sum_{B} BCQ_{k,b,h}^{m,t}\right) + \sum^{T} ISP_h^{i,t}\ x\left(\sum_{S} BCQ_{s,k,h}^{i,t} - \sum_{B} BCQ_{k,b,h}^{i,t}\right)\right]$$

Where:

'M' is the set of all *delivery points* 'm' and *intertie metering points* 'i'.

'T' is the set of all *metering intervals* 't' in *settlement hour* 'h'.

‘S’ is the set of all *selling market participants* ‘s’.

‘B’ is the set of all *buying market participants* ‘b’.

Second Settlement HPTSA – Formula Variant 1

The first variant of the HPTSA will be applicable for both dispatchable and non-dispatchable *generation facilities*, *dispatchable loads* and *boundary entities* that are financially bound to the DAM schedule from the DAM calculation engine.

$HPTSA\{2\}_{k,h}$ = [second settlement balancing amount for *delivery points* and *intertie metering points*]

$$HPTSA\{2\}\_V1_{k,h} = \sum^{M,T}\left[\left[RT\_LMP_h^{m,t}\ x\left[\left(AQEI_{k,h}^{m,t} - DAM\_QSI_{k,h}^{m}/12\right) - \left(AQEW_{k,h}^{m,t} - DAM\_QSW_{k,h}^{m}/12\right)\right]\right] + \left[ISP_h^{i,t}\ x\left[\left(SQEI_{k,h}^{i,t} - DAM\_QSI_{k,h}^{i}/12\right) - \left(SQEW_{k,h}^{i,t} - DAM\_QSW_{k,h}^{i}/12\right)\right]\right]\right]$$

Where:

‘M’ is the set of all dispatchable and non-dispatchable *generation facilities* and *dispatchable load delivery points* ‘m’ and *intertie metering points* ‘i’.

‘T’ is the set of all *metering intervals* ‘t’ in *settlement hour* ‘h’.

Second Settlement HPTSA – Formula Variant 2

This variant will be applicable specifically to price responsive loads. This includes price responsive loads that are scheduled by the DAM calculation engine to withdraw energy and physical *hourly demand response* resources that are registered as price responsive loads to fulfil their physical *demand response capacity obligation*. The DAM financially binding schedules for these physical *hourly demand response* resources will be combined with the DAM financially binding schedules for the price responsive load to calculate the second *settlement* amount for the price responsive load.

Both the price responsive load and physical *hourly demand response* resource must have the same *metered market participant*.

The formulation of the HPTSA – Formula Variant 2 during second *settlement* is as follows:

$$HPTSA\{2\}\_V2_{k,h} = \sum^{M1,T}\left[\left[RT\_LMP_h^{m,t}\ x\left(AQEW_{k,h}^{m,t} - DAM\_QSW_{k,h}^{m}/12\right)\right]\right] - \sum^{M2,T}\left[RT\_LMP_h^{m,t}\ x\ DAM\_QSW_{k,h}^{m}/12\right]$$

Where:

‘M1’ is the set of all *delivery points* ‘m’ for price responsive loads.

‘M2’ is the set of all *delivery points* ‘m’ for price responsive loads used as an *hourly demand response* resource to fulfil a *demand response capacity obligation.*

‘T’ is the set of all *metering intervals* ‘t’ in *settlement hour* ‘h’.

3.6.2.2 Second Settlement Calculation: Hourly Virtual Transaction Settlement Amount (HVTSA {2})

The second *settlement* calculation of the HVTSA will reflect any data corrections between the first and second *settlement* and will also provide the *market participant* the opportunity to raise a NoD, if required. Specifically, the virtual transaction is purely based upon the *energy* price difference between the DAM and the *real-time market*.

Table 3-48: Resolution of HVTSA{2} Calculation

Attribute	Resolution
Second *settlement* time resolution	Hourly
Geographic resolution	Virtual transaction zonal trading entity
DAM price accuracy	\$/MWh to the nearest cent
DAM *energy* quantities (virtual)	MW schedule values converted to MWh values for the purposes of *settlement* to the nearest 0.01MWh
RT price accuracy	\$/MWh to the nearest cent

Table 3-49 describes the eligibility to receive the second *settlement* HVTSA{2} on the basis of the type of *facility* or transaction involved.

Table 3-49: Eligibility for HVTSA in Second Settlement

Facility/Transaction Type	Eligible?	Special Processing Requirements
Dispatchable *generation facility*	No	Not applicable
Non-dispatchable *generation facility*	No	Not applicable
Boundary entity (imports & exports)	No	Not applicable
Price responsive load	No	Not applicable
Dispatchable load	No	Not applicable
Non-dispatchable load	No	Not applicable
Virtual transaction to buy *energy*	Yes	Same formula used for both forms of virtual transactions
Virtual transaction to sell *energy*	Yes	

Second Settlement HVTSA Formula

$$HVTSA\{2\}_{k,h} = -1\ x \sum^{V,T} (DAM\_QVSI^{v}_{k,h} - DAM\_QVSW^{v}_{k,h})/12\ x\ RT\_LMP^{v,t}_{h}$$

Where:

‘V’ is the set of all virtual transaction zonal trading entities ‘v’.

‘T’ is the set of all *metering intervals* ‘t’ in *settlement hour* ‘h’.

3.6.2.3 Second Settlement Calculation: Hourly Operating Reserve Settlement Amount (HORSA{2})

The second *settlement* of the HORSA{2} will reconcile the differences between a *market participant's* position for *operating reserve* in the day-ahead market, and their actual *real-time market* activity. This second *settlement* will reconcile any differences between the DAM quantity of *operating reserve* sold and the actual quantity provided to the *real-time market*.

The first and second *settlement* amounts will be matched to the same *facility* or *intertie* transaction, which will result in an HORSA of a level of granularity described in the next sub-section.

As mentioned earlier, the combined amounts of HORSA{1} and HORSA{2} will completely replace the Operating Reserve Settlement Credit currently in use in the *real-time market*.

Table 3-50: Resolution of HORSA{2}

Attribute	Resolution
Second *settlement* time resolution	Hourly Includes hourly aggregation of 5-minute quantities of allocated quantities of *operating reserve*
Geographic resolution	*Facilities* within Ontario: • By *delivery point* *Intertie* Transactions: • By *intertie metering point*
DAM price accuracy	$/MWh to the nearest cent
DAM class 'r' operating quantities	MW schedule values converted to MWh values for the purposes of *settlement* to the nearest 0.1 MWh
RT price accuracy	$/MWh to the nearest cent
All *real-time market settlement* data	Real-time schedule data at the *delivery points or intertie metering points* to the nearest 0.1 MWh

Table 3-51 describes the eligibility to receive the second *settlement* HORSA on the basis of the type of *facility* or transaction involved, and the variant of the general HORSA formula to be employed.

Table 3-51: Eligibility for HORSA in Second Settlement

Facility/Transaction Type	Eligible?	Special Processing Requirements
Quick start facility	Yes	Use formula variant 1
Non-dispatchable *generation facility*	No	Not applicable
Boundary entity (imports & exports)	Yes	Use formula variant 1
Price responsive load	No	Not applicable
Dispatchable load	Yes	Use formula variant 1
Non-dispatchable load	No	Not applicable
NQS *generation facility*	Yes	Use formula variant 1
Virtual transaction to buy	No	Not applicable

Facility/Transaction Type	Eligible?	Special Processing Requirements
Virtual transaction to sell	No	Not applicable

Second Settlement HORSA – Formula Variant 1

The first variant of the HORSA will be applicable for all eligible *operating reserve* transactions.

$$HORSA\{2\}_{k,h} = \sum_{R}^{M,T} RT\_PROR_{r,h}^{m,t}\ x\ \left(RT\_QSOR_{r,k,h}^{m,t} - DAM\_QSOR_{r,k,h}^{m}/12\right) + RT\_PROR_{r,h}^{i,t}\ x\ \left(RT\_QSOR_{r,k,h}^{i,t} - DAM\_QSOR_{r,k,h}^{i}/12\right)$$

Where:

'M'	is the set of all *delivery points* 'm' and *intertie metering points* 'i'.
'T'	is the set of all *metering intervals* 't' in *settlement hour* 'h'.
'R'	is the set of each class r of *operating reserve.*

3.6.2.4 Second Settlement Calculation: DAM Operating Reserve Uplift (DORU)

The DAM Operating Reserve Uplift (DORU) will recover *operating reserve* costs incurred in the DAM and the *real-time market* as represented by the cumulative amount of all HORSA paid to individual DAM *market participants* in each hour and is calculated as:

HORSA = HORSA{1} + HORSA{2}

The DORU amount will be allocated on a pro-rata basis to all *real-time market* loads and exports on an hourly basis.

The formulation of the DORU is as follows:

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

Where:

'M'	is the set of all *delivery points* 'm' and *intertie metering points* 'i'.
'T'	is the set of all *metering intervals* 't' in *settlement hour* 'h'.
'K'	is the set of all *market participants* 'k'.
'$RQ_{k,h}^{m,i,t}$'	as defined in Section 3.5.6 Table 3-36.

3.6.3 Non-Dispatchable Load Settlement

Market participants will not submit *bids* for *energy* into the day-ahead market or the *real-time market* for *non-dispatchable loads*. As is the case in the current *real-time market*, the *IESO* will represent *non-dispatchable loads* as part of the hourly average NDL *demand* forecasts to be used by the DAM calculation engine and the PD calculation engine.

The *settlement* of *energy* for *non-dispatchable loads* will be based on the allocated quantity of *energy* withdrawn at the *delivery point* for the *load facility* in real-time. The quantity of *energy* scheduled for withdrawal by the DAM calculation engine will be based on the *IESO* average NDL *demand* forecast and *hourly demand response* resources that are not registered as a price responsive load. Therefore, a *market participant* will not receive a *settlement amount* for a *non-dispatchable load* unless *energy* is consumed in real-time.

Load forecast deviations may occur when the real-time load quantity of *energy* withdrawn differs from the quantity scheduled for *non-dispatchable loads* by the DAM calculation engine. When such deviations occur, there may be a cost impact arising from the change in the quantity of MWs over which *energy* costs are recovered in real-time, versus the quantity of MWs that were scheduled by the DAM calculation engine for *non-dispatchable loads* and *hourly demand response* resources that are not registered as a price responsive load.

The total cost of the forecast deviation consists of two elements:

- Real-Time Purchase Cost/Benefit, which measures the cost of a day-ahead under-forecast, or conversely the benefit of a day-ahead over-forecast, for *non-dispatchable loads*, and
- DAM Volume Factor Cost/Benefit, which measures the impact of forecast deviation on the per-MWh cost of day-ahead schedules for *non-dispatchable loads and hourly demand response* resources that are not registered as a price responsive load.

Both the Real-Time Purchase Cost/Benefit and the DAM Volume Factor Cost/Benefit can be a positive or negative number. The cost/benefit of these two elements will be recovered through an adjustment to the DAM hourly Ontario zonal price.

3.6.3.1 Real-Time Purchase Cost/Benefit

The total hourly cost to the province due to real-time purchases for *non-dispatchable loads* scheduled in the day-ahead or the benefit of real-time sales for *non-dispatchable loads* scheduled in the day-ahead arising from the forecast deviation is represented as:

$$Real - Time\ Purchase\ Cost\_Benefit = \sum_{K,h}^{M,T} \left[RT\_LMP_{h}^{m,t}\ x\ (AQEW_{k,h}^{m,t} - DAM\_QSW_{k,h}^{m}/12) \right] - \sum_{K,h}^{M2,T} \left[RT\_LMP_{h}^{m,t}\ x\ DAM\_QSW_{k,h}^{m}/12 \right]$$

Where:

'M'	is the set of all *delivery points* 'm'.
'M2'	is the set of all *delivery points* 'm' relating to *hourly demand response* resources that are not registered as *price responsive load.*[2]
'T'	is the set of all *metering intervals* 't' in *settlement hour* 'h'.
'K'	is the set of all *market participants* 'k' with NDL *facilities*.

[2] M2 is not included within M.

3.6.3.2 DAM Volume Factor Cost/Benefit

The total hourly cost to the province due to the change in MW volume of *energy* scheduled in the day-ahead for *non-dispatchable load* arising from the forecast deviation is represented as:

$$DAM\ Volume\ Factor\ Cost\_Benefit = DAM\_LMP_h^z\ x\ \left[\sum\nolimits_{K,h}^{M,T} \left(DAM\_QSW_{k,h}^{m}/12 - AQEW_{k,h}^{m,t}\right)\right] + \sum\nolimits_{K,h}^{M2} \left[DAM\_LMP_h^z\ x\ DAM\_QSW_{k,h}^{m}\right]$$

Where:

'M'	is the set of all *delivery points* 'm'.
'M2'	is the set of all *delivery points* 'm' relating to *hourly demand response* resources that are not registered as *price responsive load.*[3]
'T'	is the set of all *metering intervals* 't' in *settlement hour* 'h'.
'K'	is the set of all *market participants* 'k' with NDL *facilities*.

The DAM Volume Factor Cost/Benefit can be calculated using zonal load quantities because the hourly zonal price applies to all quantities. This element accounts for the change in the number of MW of load over which the DAM purchase costs for *non-dispatchable load* for the province are spread.

3.6.3.3 Province-Wide Per Megawatt Charge

The total cost of the forecast deviation for *non-dispatchable load* is:

$$Total\ Cost\ of\ Forecast\ Deviation = RT\ Purchase\ Cost\_Benefit + DAM\ Volume\ Factor\ Cost\_Benefit$$

The province-wide per megawatt charge for the total cost of forecast deviation is:

$$Forecast\ Deviation\ per\ MW\ Charge = \frac{RT\ Purchase\ Cost\_Benefit + DAM\ Volume\ Factor\ Cost\_Benefit}{RT\ Energy\ Withdrawn\ by\ all\ NDL\ facilities}$$

The province-wide per megawatt charge is thus the sum of two price adjustments, specifically:

- an adjustment to the real-time LMP at the *delivery point* for each *non-dispatchable load* expressed in \$/MWh; and
- an adjustment to the DAM Ontario zonal price expressed in \$/MWh.

The price paid by *non-dispatchable loads* for the real-time allocated quantity of *energy* withdrawn will be the sum of the DAM hourly zonal price and the hourly province-wide per megawatt charge.

Table 3-52: Resolution of NDL Calculations

Attribute	Resolution
Settlement time resolution	Hourly
Geographic resolution	By *delivery point*

[3] M2 is not included within M.

Attribute	Resolution
DAM zonal price accuracy	$/MWh to the nearest cent
DAM *energy* quantities	MW schedule values converted to MWh values for the purposes of *settlement* to the nearest 0.1 MWh
RT price accuracy	$/MWh to the nearest cent
RT energy quantities	Real-time *metering data* at the *delivery points* to the nearest 0.001 MWh

3.6.3.4 NDL Settlement – Formula

Let $LFDC_h$ be the hourly province-wide forecast deviation dollars per megawatt-hour ($/MWh) charge for *non-dispatchable loads* for each *settlement hour* 'h':

$$LFDC_h = \frac{\sum_{K,h}^{M,T}\left[RT\_LMP_h^{m,t}\ x\ (AQEW_{k,h}^{m,t} - DAM\_QSW_{k,h}^{m}/12)\right] - \sum_{K,h}^{M2,T}\left[RT\_LMP_h^{m,t}\ x\ DAM\_QSW_{k,h}^{m}/12\right]}{\sum_{K,h}^{M,T} AQEW_{k,h}^{m,t}} + \frac{DAM\_LMP_h^{z}\ x\ \left[\sum_{K,h}^{M,T}\left(DAM\_QSW_{k,h}^{m}/12 - AQEW_{k,h}^{m,t}\right)\right] + \sum_{K,h}^{M2}\left[DAM\_LMP_h^{z}\ x\ DAM\_QSW_{k,h}^{m}/12\right]}{\sum_{K,h}^{M,T} AQEW_{k,h}^{m,t}}$$

Where:

'K'	is the set of all *market participants* 'k' with NDL *facilities.*
'M'	is the set of all *registered wholesale meters* (*RWMs)* 'm' relating to *non-dispatchable loads*.
'M2'	is the set of all *delivery points* 'm' relating to *hourly demand response* resources that are not registered as *price responsive load.*[4]
'T'	is the set of all *metering intervals* 't' in *settlement hour* 'h'.

The price adjustment to the DAM hourly zonal price for *non-dispatchable loads* for the province-wide allocation of the cost of forecast deviation is:

$$Price_{adj} = DAM\ Ontario\ Zonal\ Price + \ Forecast\ Deviation\ per\ MW\ Charge$$

The HPTSA for *non-dispatchable loads* is the hourly adjusted price times the allocated quantity of *energy* withdrawn by the *non-dispatchable load*:

$$HPTSA\_NDL_{k,h} = \ (DAM\_LMP_h^{z} + LFDC_h)\ x \sum^{T} AQEW_{k,h}^{m,t}$$

Where:

'T'	is the set of all *metering intervals* 't' in *settlement hour* 'h'.

[4] M2 is not included within M.

3.7 Market Charges, Credits and Uplifts

Following the first *settlement* and second *settlement* of the two-*settlement* system, there will be day-ahead market and *real-time market* charges, credits and uplifts that need to be applied to ensure financial neutrality. These market charges, credits and uplifts will appear on the *preliminary* and *final settlement statements*, along with the *settlement amounts* calculated in the first *settlement* and second *settlement* of the two-*settlement* system discussed in Section 3.6.

Table 3-53 summarizes the new *settlement amounts* that are calculated outside of the two-*settlement* system.

Table 3-53: Settlement Amounts Calculated Following DAM

Name	Acronym	Section Reference
Day-Ahead Market Make-Whole Payment	DAM_MWP	3.7.1
Day-Ahead Market Generator Offer Guarantee	DAM_GOG	3.7.2
Day-Ahead Market Make-Whole Payment Uplift	DAM_MWPU	3.7.3
Day-Ahead Market Reliability Scheduling Uplift	DRSU	3.7.4
Real-Time Make-Whole Payment	RT_MWP	3.7.5
Real-Time Make-Whole Payment Uplift	RT_MWPU	3.7.6
DAM Balancing Credit	DAM_BC	3.7.7
DAM Balancing Credit Uplift	DAM_BCU	3.7.8
Real-Time Generator Offer Guarantee	RT_GOG	3.7.9
Real-Time Generator Offer Guarantee Uplift	RT_GOGU	3.7.10
Generator Failure Charge – Market Price Component	GFC_MPC	3.7.11
Generator Failure Charge – Guarantee Cost Component	GFC_GCC	3.7.11
Generator Failure Charge – Market Price Component Uplift	GFC_MPCU	3.7.12
Generator Failure Charge – Guarantee Cost Component Uplift	GFC_GCCU	3.7.13
Congestion Rent and Loss Residuals Disbursement	CRLRD	3.7.14
Real-Time Operating Reserve Shortfall Debit	RT_ORSD	3.7.16
Real-Time Operating Reserve Shortfall Debit Uplift	RT_ORSDU	3.7.16
Real-Time Intertie Failure Charge	RT_INFC	3.7.16
Real-Time Intertie Failure Charge Uplift	RT_INFCU	3.7.16
Real-Time Intertie Offer Guarantee	RT_IOG	3.7.16
Real-Time Intertie Offer Guarantee Uplift	RT_IOGU	3.7.16
Real-Time Ramp-Down Settlement Amount	RT_RDSA	3.7.16
Real-Time Ramp-Down Settlement Amount Uplift	RT_RDSAU	3.7.16
DAM Reference Level Settlement Charge	DAM_RLSC	3.13.2
Real-Time Reference Level Settlement Charge	RT_RLSC	3.13.2
Reference Level Settlement Charge Uplift	RLSCU	3.13.3

Name	Acronym	Section Reference
Ex-Post Mitigation for Physical Withholding Settlement Charge	EXP_PWSC	3.13.4
Ex-Post Mitigation for Economic Withholding on Uncompetitive Interties Settlement Charge	EXP_EWSC	3.13.4
Ex-Post Mitigation Settlement Charge Uplift	EXP_MSCU	3.13.5

The *IESO* may apply a 'reason code' when it manually alters an import or export schedule. The reason codes are defined in the Grid and Market Operations Integration detailed design document. Table 3-54 lists the reason codes and the resulting *settlement* treatment. For the RT Failure Charge, a 'Yes' means that the transaction is exempt from the failure charge. For all other columns, a 'Yes' means that the transaction is eligible for the *settlement amount*.

Table 3-54: Intertie Reason Codes and their Eligibility for MWP and Intertie Failure Charges

Code Entered	Real-Time Intertie Failure Charge Exempt	Day-Ahead Market Balancing Credit	RT-Intertie Offer Guarantee	RT Import Make-Whole for Operating Reserve	RT Export Make-Whole for PD Pricing[1] Discrepancy	RT Export Make-Whole for Manual Dispatch Out-of-Merit
AUTO	Not applicable	No	Yes	Yes	Yes	No
NY90 – MAX	Not applicable	No	Yes	Yes	Yes	No
MrNh – MAX	Yes	No	Yes	Yes	Yes	No
OTH – MAX	No	No	Yes	Yes	Yes	No
TLRe – MAX	Yes	No	Yes	Yes	Yes	No
TLRi – MAX	Yes	Yes	Yes	Yes	Yes	No
ADQh – MAX	Yes	Yes	Yes	Yes	Yes	No
ADQh – MIN	Yes	No	Yes	Yes	Yes	Yes[2]
ORA – MIN	Yes	No	Yes	Yes	Yes	Yes[2]
TLRi - MIN	Yes	No	Yes	Yes	Yes	Yes[2]
ADQh - FIX	Yes	Yes	Yes	Yes	No	Yes
TLRi - FIX	Yes	Yes	Yes	Yes	No	Yes

The *IESO* will determine whether the code was responsible for the scheduling outcome. If the code was not responsible for the scheduling outcome, the failure charge exemption and make-whole eligibility will be based on the 'AUTO' code.

Note:

- The RT Export PD Pricing Discrepancy MWP only applies when an RT export was scheduled without the influence of any operator adjustments that served to fix or increase the export schedule.
- In the event that the code is not responsible for the scheduling outcome, then the RT export will be eligible for the RT Export PD Pricing Discrepancy MWP.

3.7.1 DAM Make-Whole Payment (DAM_MWP)

The DAM make-whole payment (DAM_MWP) provides a *settlement amount* to dispatchable *generation facilities*, *dispatchable loads*, price responsive loads and *boundary entities* that are scheduled in the day-ahead market when the *market participant* would otherwise incur an implied loss. Although price responsive loads and *boundary entities* are not dispatchable on a five-minute basis in real time, they can receive hourly schedules in the DAM and are, therefore, eligible for the DAM_MWP.

An implied loss is incurred when the *energy* and *operating reserve* revenue earned is insufficient to cover the *offer* costs or *bid* benefits of the *market participant*, subject to the mitigation process. An implied loss can occur even when a *facility* is economically scheduled. DAM_MWP will incorporate any required adjustment and mitigation test results into the calculation set out by the market power mitigation process, which is described in Section 3.13.

The DAM calculation engine will maximize the gains from trade over an entire 24-hour period given *market participant offers* and *bids*, resource constraints and the *reliability* needs of the system. At times, the most efficient and reliable schedule for the system as a whole can result in some *facilities* being scheduled at an implied loss. A *facility* could be scheduled in the DAM at a loss in order to meet all system constraints for *reliability*, for example, to avoid violation of a transmission limit.

In the case of dispatchable *generation facilities*, such revenues and costs will include:

- All revenues associated with the supply of *energy* and *operating reserve* in the DAM; and
- Costs of production implied[5] by *offers* for *energy* and *operating reserve*.

In the case of *dispatchable loads*, such revenues and costs will include:

- All revenues associated with the provision of reduced *energy* withdrawals and *operating reserve* in the DAM; and
- *Costs* associated with the provision of reduced *energy* withdrawals and *operating reserve* implied by *bids* for *energy* and *offers* for *operating reserve*.

In the case of *boundary entities*, such revenues and costs will include:

- All revenues associated with the supply of *energy* and *operating reserve* by imports in the DAM;
- All revenues associated with the provision of reduced *energy* withdrawals by exports in the DAM;
- Costs of supplying *energy* or *operating reserve* by imports implied by *offers* to supply *energy* or *operating reserve;* and

[5] This means that the costs eligible for recovery may not be the actual costs. The cost eligible for recovery will be the cost implied by the offer, subject to mitigation.

- Costs associated with the provision of reduced *energy* withdrawals by exports implied by *bids* for *energy*.

In the case of price responsive loads, such revenues and costs will include:

- All revenues associated with the provision of reduced *energy* withdrawals in the DAM; and
- Costs associated with the provision of reduced *energy* withdrawals implied by *bids* for *energy*.

All costs associated with the DAM_MWP will be recovered through the DAM_MWP Uplift.

Table 3-55: Resolution of DAM_MWP Calculations

Attribute	Resolution
Settlement time resolution	Hourly
Geographic resolution	*Facilities* within Ontario: • By *delivery point* *Intertie* Transactions: • By *intertie metering point*
DAM price accuracy	$/MWh to the nearest cent
DAM *energy* quantities	MW schedule values converted to MWh values for the purposes of *settlement* to the nearest 0.1 MWh

3.7.1.1 Eligibility for DAM_MWP

All dispatchable *generation facilities*, *boundary entities*, price responsive loads and *dispatchable loads* are eligible for DAM_MWP. However, dispatchable *generation facilities* are not eligible for DAM_MWP during the period in which they are ramping to meet MLP. There are specific eligibility requirements for *called capacity exports* and *generation facilities* with a minimum daily energy limit.

Eligibility for Called Capacity Exports

A *generation unit* within the *IESO control area* will not be eligible for DAM_MWP in an hour in which it commits its capacity to an external *control area* and:

- the external *control area operator* has called an *energy* export supported by the *generation unit* prior to the *generation unit* being scheduled in the day-ahead market; or
- the external *control area operator* has called an *energy* export supported by the *generation unit* after the *generation unit* has received a DAM financially binding schedule, and the *IESO* is restricting other transactions on the *interconnected systems*, while maintaining the *called capacity export* transaction.
    - This addresses system *adequacy* issues where the *IESO* is managing system *adequacy* while maintaining a *called capacity export* backed by a *generation unit* that has a DAM schedule or commitment.

Eligibility for a Generation Facility with Minimum Daily Energy Limit

A *generation facility* with a minimum daily energy limit (DEL) will not be eligible to recover its *energy* cost if:

- it is scheduled to supply *energy* across a *trading day* to meet only its minimum DEL; or

- it is scheduled to supply *energy* across the day above its minimum DEL, but the *facility* was only able to satisfy its minimum DEL after taking into account its minimum hourly output and minimum hourly must run across the *trading day*.

Furthermore, such a *generation facility* will not be compensated for the hours where it received a schedule to supply *energy* at its minimum hourly must run; at its minimum hourly output; or within or at the boundary of a *forbidden region* such parameters provided by the *market participant* as part of submitted *dispatch data*. Nonetheless, for any hours that the *generation facility* receives a *reliability* constraint, it will be able to recover its costs through a DAM_MWP, subject to market power mitigation. The DAM_MWP will provide the incentive for the *generation facility* to respond to the *IESO dispatch instructions*.

DAM_MWP for these *generation facilities* will be assessed on a *per-start* basis when the number of starts within a *trading day* is equal to the *maximum number of starts per day* parameter provided by the *market participant* as part of the daily *dispatch data*. A start is a set of continuous hours with a DAM financial binding schedule at or above a start indicator value. All hours that are not part of a start will be assessed separately.

3.7.1.2 DAM_MWP Formulation

DAM_MWP will be broken down into two components:

- Component 1: Any shortfall in payment on the DAM financially binding schedule for *energy* will be based upon the revenue received for that amount of *energy* committed in DAM in comparison with the cost represented in the DAM *offers* or *bids* for *energy* above its DAM economic operating point.
- Component 2: Any shortfall in payment on the DAM financially binding schedule for *operating reserves* will be based upon the revenue received for that amount of *operating reserves* committed in DAM in comparison with the cost represented in the DAM *operating reserve offers* above its DAM economic operating point.

The DAM_MWP will be calculated for each hour for which a *facility* received a DAM financially binding schedule from the DAM calculation engine. DAM_MWP will be calculated as the sum of Component 1 and Component 2.

$$DAM\_MWP = Max(0, Component\ 1 + Component\ 2)$$

For a dispatchable *generation facility* or a *dispatchable load:*

$$DAM\_MWP^{m}_{k,h} = Max\left[0, DAM\_COMP1^{m}_{k,h} + DAM\_COMP2^{m}_{k,h}\right]$$

For cascade hydroelectric *generation facilities* with linkages between one or more *generation facilities*, DAM_MWP needs to be calculated across all linked resources in order to offset profit and loss across all linked resources. DAM_MWP can be calculated as:

$$\sum^{M}\left[DAM\_COMP1^{m}_{k,h+TL_m} + DAM\_COMP2^{m}_{k,h+TL_m}\right] > 0$$

Where:

‘M’	is the set of all *delivery points* ‘m’ of linked hydroelectric *generation facilities.*
‘TL_m’	is the time-lag, for each *delivery point* ‘m’, equal to the number of hours downstream that the *delivery point* is from the furthest upstream *delivery point* determined by the

submitted Linked Resources, Time Lag, MWh *dispatch data* parameters for the linked hydroelectric *generation facilities.*

Then, for every *delivery point* 'm':

$$DAM\_MWP^{m}_{k,h+TL_m} = DAM\_COMP1^{m}_{k,h+TL_m} + DAM\_COMP2^{m}_{k,h+TL_m}$$

Otherwise:

$$DAM\_MWP^{m}_{k,h+TL_m} = 0$$

For a price responsive load, DAM_MWP will be calculated for Component 1 only because PRLs are not eligible to offer *operating reserves*. The DAM_MWP can be calculated as:

$$DAM\_MWP^{m}_{k,h} = Max\left[0, DAM\_COMP1^{m}_{k,h}\right]$$

For a *boundary entity*:

$$DAM\_MWP^{i}_{k,h} = Max\left[0, DAM\_COMP1^{i}_{k,h} + DAM\_COMP2^{i}_{k,h}\right]$$

Operating Profit Function

The operating function (OP) is defined in the *IESO* market rules Section 9.3.8A.2.

Let DAM_BE be a matrix of 'n' *price-quantity pairs offered* by *market participant* 'k' to supply *energy* during the *settlement hour* 'h' in the day-ahead market.

Let DAM_BL be a matrix of 'n' *price-quantity pairs bid* by *market participant* 'k' to withdraw *energy* during the *settlement hour* 'h' in the day-ahead market.

Let DAM_BOR be a matrix of 'n' *price-quantity pairs offered* by *market participant* 'k' to supply *class r operating reserve* during the *settlement hour* 'h' in the day-ahead market.

Let OP (P, Q, B) be a profit function of Price (P), Quantity (Q) and an 'n' x 2 matrix (B) of the *offered* or *bid price-quantity pairs*:

$$OP(P, Q, B) = P.Q - \sum_{n=1}^{s^*} P_n \, x \, (Q_n - Q_{n-1}) + (Q - Q_{s^*}) \, x \, P_{s^*+1}$$

Where:

's*'	is the highest indexed row of matrix B such that $Q_{s^*} \leq Q \leq Q_n$ and $Q_n = 0$.
'B'	is the matrix DAM_BE, DAM_BL or DAM_BOR.

The two components will be calculated using the operating profit function described above.

Component 1

For dispatchable *generation facilities*:

$$DAM\_COMP1^{m}_{k,h} = -1 \, x \, Min\left\{0, \left[OP\left(DAM\_LMP^{m}_{h}, DAM\_QSI^{m}_{k,h}, DAM\_BE^{m}_{k,h}\right) - OP\left(DAM\_LMP^{m}_{h}, DAM\_EOP^{m}_{k,h}, DAM\_BE^{m}_{k,h}\right)\right]\right\}$$

Where:

'EOP'	DAM variables with 'EOP' are defined in Section 3.5.4 Table 3-17.

For cascade hydroelectric *generation facilities* with linkages between one or more *generation facilities*:

$$DAM\_COMP1_{k,h}^{m} = (-1) \times \{OP[DAM\_LMP_{h}^{m}, DAM\_QSI_{k,h}^{m}, DAM\_BE_{k,h}^{m}] - OP[DAM\_LMP_{h}^{m}, DAM\_EOP_{k,h}^{m}, DAM\_BE_{k,h}^{m}]\}$$

Where:

‘EOP’ DAM variables with ‘EOP’ are defined in Section 3.5.4 Table 3-17.

For *dispatchable loads* and price responsive loads that are not also registered as a physical *hourly demand response* resource:

$$DAM\_COMP1_{k,h}^{m} = Min\{0, OP(DAM\_LMP_{h}^{m}, DAM\_QSW_{k,h}^{m}, DAM\_BL_{k,h}^{m}) - OP(DAM\_LMP_{h}^{m}, DAM\_EOP_{k,h}^{m}, DAM\_BL_{k,h}^{m})\}$$

Where:

‘EOP’ DAM variables with ‘EOP’ are defined in Section 3.5.4 Table 3-17.

For imports:

$$DAM\_COMP1_{k,h}^{i} = -1\ x\ Min\{0, [OP(DAM\_LMP_{h}^{i}, DAM\_QSI_{k,h}^{i}, DAM\_BE_{k,h}^{i}) - OP(DAM\_LMP_{h}^{i}, DAM\_EOP_{k,h}^{i}, DAM\_BE_{k,h}^{i})]\}$$

Where:

‘EOP’ DAM variables with ‘EOP’ are defined in Section 3.5.4 Table 3-17.

For exports:

$$DAM\_COMP1_{k,h}^{i} = Min\{0, OP(DAM\_LMP_{h}^{i}, DAM\_QSW_{k,h}^{i}, DAM\_BL_{k,h}^{i}) - OP(DAM\_LMP_{h}^{i}, DAM\_EOP_{k,h}^{i}, DAM\_BL_{k,h}^{i})\}$$

Where:

‘EOP’ DAM variables with ‘EOP’ are defined in Section 3.5.4 Table 3-17.

For price responsive loads that are also registered as a physical *hourly demand response* resource, DAM_MWP will be calculated as the sum of the DAM_MWP at the price responsive load *delivery point* ‘m’ and the physical *hourly demand response* resource *delivery point* ‘m1’ that is registered as a price responsive load. The *registered market participant* and the *metered market participant* ‘k’ must be the same for both the price responsive load *delivery point* and the physical *hourly demand response* resource. The DAM_MWP will be calculated as:

$$DAM\_COMP1_{k,h}^{m} = Min\{0, [OP(DAM\_LMP_{h}^{m}, DAM\_QSW_{k,h}^{m}, DAM\_BL_{k,h}^{m}) - OP(DAM\_LMP_{h}^{m}, DAM\_EOP_{k,h}^{m}, DAM\_BL_{k,h}^{m})]\} + Min\{0, [OP(DAM\_LMP_{h}^{m1}, DAM\_QSW_{k,h}^{m1}, DAM\_BL_{k,h}^{m1}) - OP(DAM\_LMP_{h}^{m1}, DAM\_EOP_{k,h}^{m1}, DAM\_BL_{k,h}^{m1})]\}$$

Where:

‘m’ is the *delivery point* for the price responsive load *metered market participant* ‘k’.

'm1' is the *delivery point* for the physical *hourly demand response* resource that is registered as the price responsive load *metered market participant* 'k'.

'EOP' DAM variables with 'EOP' are defined in Section 3.5.4 Table 3-17.

Component 2

For an import:

$$DAM\_COMP2^{i}_{k,h} = -1\,x \sum_{R} Min\{0, [OP(DAM\_PROR^{i}_{r,h}, DAM\_QSOR^{i}_{r,k,h}, DAM\_BOR^{i}_{r,k,h}) - OP(DAM\_PROR^{i}_{r,h}, DAM\_EOP^{i}_{r,k,h}, DAM\_BOR^{i}_{r,k,h})]\}$$

Where:

'R' is the set of each class r of *operating reserve*.

'EOP' DAM variables with 'EOP' are defined in Section 3.5.4 Table 3-17.

For a dispatchable *generation facility* or a *dispatchable load:*

$$DAM\_COMP2^{m}_{k,h} = -1\,x \sum_{R} Min\{0, [OP(DAM\_PROR^{m}_{r,h}, DAM\_QSOR^{m}_{r,k,h}, DAM\_BOR^{m}_{r,k,h}) - OP(DAM\_PROR^{m}_{r,h}, DAM\_EOP^{m}_{r,k,h}, DAM\_BOR^{m}_{r,k,h})]\}$$

Where:

'R' is the set of each class r of *operating reserve*.

'EOP' DAM variables with 'EOP' are defined in Section 3.5.4 Table 3-17.

For cascade hydroelectric *generation facilities* with linkages between one or more *generation facilities*:

$$DAM\_COMP2^{m}_{k,h} = (-1) \times \sum_{R} \{OP[DAM\_PROR^{m}_{r,h}, DAM\_QSOR^{m}_{r,k,h}, DAM\_BOR^{m}_{r,k,h}] - OP[DAM\_PROR^{m}_{r,h}, DAM\_OR\_EOP^{m}_{r,k,h}, DAM\_BOR^{m}_{r,k,h}]\}$$

Where:

'R' is the set of each class r of *operating reserve*.

'EOP' DAM variables with 'EOP' are defined in Section 3.5.4 Table 3-17.

3.7.1.3 Pseudo-Unit Settlement – DAM_MWP Formulation

As with all other dispatchable *generation facilities,* an NQS *generation unit* associated with a *pseudo-unit* will automatically be eligible for a DAM_MWP in every hour that it received a DAM financially binding schedule from the DAM calculation engine. NQS *generation facilities* are not eligible for DAM_MWP during the ramp-up period established by the ramp up energy to MLP daily *dispatch data* parameter.

Calculation of the DAM_MWP for *pseudo-units* will require derivation of *facility*-based *offers* from the submitted PSU *offers.*

The DAM_MWP calculation for a combustion turbine (CT) associated with a *pseudo-unit* will use a single Derived Interval Price Curve (DIPC) for *energy offers* and another for *operating reserve offers*.

Each DIPC for the CT will be constructed from the greater of DAM_QSI and DAM_EOP for the corresponding *pseudo-unit* so that the operating profits at both levels of CT output can be calculated from the same DIPC.

The DAM_MWP calculation for a steam turbine (ST) associated with a *pseudo-unit* will require two separate versions of DIPC and DIGQ for both *energy* and OR *offers*. There will be a version of DIPC/DIGQ constructed from the associated *pseudo-units'* DAM_QSI values and another version constructed from the associated *pseudo-units'* DAM_EOP values for both *energy* and *operating reserve offers*. The ST DAM_MWP calculation requires two separate sets of DIPC/DIGQ because the underlying differences in QSI and EOP across multiple associated PSUs can change the offer laminations that should be included in the implied ST price curve.

Together, these formulations will allow comparisons in the day-ahead timeframe at each *facility* between expected operating profits (or losses) at the scheduled level of output and the economically optimal level of output.

The calculation of DAM_MWP for an NQS *generation unit* combustion turbine (CT) or steam turbine (ST) associated with a *pseudo-unit* is broken down into the same two (2) components as the DAM_MWP for non-PSU NQS *generation units*, as further described in the sections below.

The DAM_MWP for a *pseudo-unit* will be calculated for each hour for which an NQS *generation unit* received a DAM financially binding schedule from the DAM calculation engine. DAM_MWP will be calculated as the sum of Component 1 and Component 2.

Component 1

Component 1 is the shortfall in payment for the CT's/ST's share of the PSU's DAM financially binding schedule for *energy* based upon the revenue received for that *energy* committed in DAM in comparison with the cost represented in the DAM *offers* for *energy* above its DAM economic operating point.

For a CT associated with a *pseudo-unit*:

$$
\begin{aligned}
&DAM\_COMP1^{c}_{k,h} \\
&\qquad = -1\ x\ Min\big[0, OP\big(DAM\_LMP^{c}_{h}, DAM\_QSI^{c}_{k,h}, DAM\_MWP\_DIPC^{c}_{k,h}\big) \\
&\qquad - OP\big(DAM\_LMP^{c}_{h}, DAM\_EOP^{c}_{k,h}, DAM\_MWP\_DIPC^{c}_{k,h}\big)\big]
\end{aligned}
$$

For an ST associated with a *pseudo-unit*:

$$
\begin{aligned}
&DAM\_COMP1^{s}_{k,h} \\
&\qquad = -1\ x\ Min\big[0, OP\big(DAM\_LMP^{s}_{h}, DAM\_QSI\_DIGQ^{s}_{k,h}, DAM\_QSI\_DIPC^{s}_{k,h}\big) \\
&\qquad - OP\big(DAM\_LMP^{s}_{h}, DAM\_EOP\_DIGQ^{s}_{k,h}, DAM\_EOP\_DIPC^{s}_{k,h}\big)\big]
\end{aligned}
$$

Where:

'c'	is combustion turbine (CT) *delivery point.*
's'	is steam turbine (ST) *delivery point.*
'EOP'	DAM variables with 'EOP' are defined in Section 3.5.4 Table 3-17.
'DIPC'	DAM variables with 'DIPC' are defined in Section 3.5.4 Table 3-17.
'DIGQ'	DAM variables with 'DIGQ' are defined in Section 3.5.4 Table 3-17.

Component 2

Component 2 is the shortfall in payment for the CT's/ST's share of the PSU's DAM financially binding schedule for *operating reserves* committed in DAM in comparison with the cost represented in the DAM *operating reserve offers* above its DAM economic operating point.

For a CT associated with a *pseudo-unit*:

$$DAM\_COMP2^{c}_{k,h} = -1\ x \sum_{R} \{Min[0, OP(DAM\_PROR^{c}_{r,h}, DAM\_QSOR^{c}_{r,k,h}, DAM\_QSOR\_DIPC^{c}_{r,k,h}) - OP(DAM\_PROR^{c}_{r,h}, DAM\_EOP^{c}_{r,k,h}, DAM\_QSOR\_DIPC^{c}_{r,k,h})]\}$$

For an ST associated with a *pseudo-unit*:

$$DAM\_COMP2^{s}_{k,h} = -1\ x \sum_{R} \{Min[0, OP(DAM\_PROR^{s}_{r,h}, DAM\_QSOR\_DIGQ^{s}_{r,k,h}, DAM\_QSOR\_DIPC^{s}_{r,k,h}) - OP(DAM\_PROR^{s}_{r,h}, DAM\_OR\_EOP\_DIGQ^{s}_{r,k,h}, DAM\_OR\_EOP\_DIPC^{s}_{r,k,h})]\}$$

Where:

‘R’	is the set of each class r of *operating reserve.*
‘EOP’	DAM variables with ‘EOP’ are defined in Section 3.5.4 Table 3-17.
‘DIPC’	DAM variables with ‘DIPC’ are defined in Section 3.5.4 Table 3-17.
‘DIGQ’	DAM variables with ‘DIGQ’ are defined in Section 3.5.4 Table 3-17.

3.7.2 DAM Generator Offer Guarantee (DAM_GOG)

The DAM_GOG payment will be calculated for *market participants* with eligible NQS *generation units* that are committed during the DAM timeframe. The DAM_GOG payment will replace the Day-Ahead Production Cost Guarantee (DA-PCG) currently in use in the DACP. The *IESO* will provide the DAM_GOG payment to compensate *market participants* for any loss they incur. This loss is relative to the costs implied by the *market participant offers* for the period in which their resource is committed by the DAM calculation engine. DAM_GOG will incorporate any required adjustment and mitigation test results into the calculation set out by the market power mitigation process, which is described in Section 3.13.

All costs associated with the DAM_GOG will be recovered through the DAM_MWP Uplift.

Table 3-56: Resolution of DAM_GOG Calculations

Attribute	Resolution
Settlement time resolution	Hourly
Geographic resolution	*Facilities* within Ontario: • By *delivery point*
DAM price accuracy	$/MWh to the nearest cent
DAM *energy* quantities	MW schedule values converted to MWh values for the purposes of *settlement* to the nearest 0.1 MWh
RT energy quantities	Real-time revenue *metering data* at the *delivery points* to the nearest 0.001 MWh

3.7.2.1 NQS Generation Unit Eligibility for DAM_GOG

An NQS *generation unit* not associated with a *pseudo-unit* will be eligible for a DAM_GOG if it meets all of the following criteria:

- the *generation unit* is not a quick-start unit;
- the *generation unit* has a *minimum loading point* (MLP) greater than 0 MW;
- the *generation unit* has a *minimum generation block run-time* (MGBRT) greater than one hour; and
- the *generation unit has* an *elapsed time to dispatch* greater than one hour as recorded during the Facility Registration process.

An eligible NQS *generation facility* will be required to meet additional conditions in order to recover the implied cost of any start-up offer and the implied cost of any speed no-load offer.

Eligibility for Recovery of Implied Cost of Start-Up Offers

An NQS *generation unit* not associated with a *pseudo-unit* will be eligible to recover the implied costs of any start-up offer if:

- the *generation unit* synchronizes and comes online in real time;
- the *generation unit* attains the MLP within the first 90 minutes of its DAM schedule or earlier as a result of being advanced by PD;
- the DAM commitment does not immediately follow another commitment period under which a start-up offer is already guaranteed; and
- the *generation unit* has completed its MGBRT.

However, the *IESO* will withhold or reduce the implied cost of start-up offers depending on when the *generation unit* actually reaches the MLP.

Table 3-57 describes the eligibility to recover the implied cost of start-up offers on the basis of when the resource achieves the MLP in order to meet its DAM financially binding schedule.

Table 3-57: Eligibility to Recover Implied Cost of Start-Up Offers

When did the resource reach MLP?	Start-up offer recovery
Within 30 minutes of the first hour of its MGBRT	Full
Within 30 to 90 minutes of its MGBRT	Reduce by 1/12 for every 5-minute interval that it was more than 30 minutes late getting to MLP
90 minutes after the start of the first hour of its MGBRT	None
Advanced by PD to come online earlier than DAM commitment	Full

Eligibility for Recovery of Implied Cost of Speed No-Load Offers

The *IESO* will apply the following guidelines to determine the eligibility of an NQS *generation unit* not associated with a *pseudo-unit* to recover the implied cost of speed no-load offers:

- An NQS *generation unit* will be eligible to recover these costs for each hour of its DAM schedule if the *generation unit* actually produces *energy* for the entire hour; and
- The *IESO* will reduce the implied cost of any speed no-load offer by 1/12th for each 5-minute interval where the *generation unit* did not produce *energy* for the full hour.

3.7.2.2 Interactions and Special Considerations

De-Commitment of a NQS Generation Unit

A *generation unit* may be de-committed by the *IESO* for *reliability*, *security* or *adequacy* reasons after the unit receives a DAM commitment. In the event that a *generation unit* is de-committed:

- after the start of its DAM commitment, the total start-up offer will be included in the assessment of the DAM_GOG as well as the speed no-load offer incurred for the hours that the unit was online; and
- prior to the start of its DAM commitment, DAM_GOG will not be assessed. However, in addition to DAM_MWP, the *generation unit* will be able to recover any negative buyback, which is described in Section 3.7.7: DAM Balancing Credit (DAM_BC).

End of Trading Day Commitment of NQS Generation Units

The DAM calculation engine will commit a NQS *generation unit* toward the end of the *trading day* when economic, even if its MGBRT will require it to run beyond the end of the *trading day*. *Registered market participants* must submit escalating start-up offers at the end of the DAM *trading day* to capture costs of the start-up offer, speed no-load offer and *energy offer* to the MLP for each possible commitment hour in the next *trading day*.

Called Capacity Exports

A *generation unit* within the *IESO control area* will not be eligible for DAM_GOG if it commits its capacity to an external *control area* and:

- the external *control area operator* has called an *energy* export supported by the *generation unit* prior to the *generation unit* being scheduled in the day-ahead market; or
- the external *control area operator* has called an *energy* export supported by the *generation unit* after the *generation unit* has received a DAM commitment, and the *IESO* is restricting other transactions on the *interconnected systems*, while maintaining the *called capacity export* transaction.
    - o this addresses system adequacy issues where the *IESO* is managing system *adequacy* while maintaining a *called capacity export* backed by a *generation unit* that has a DAM schedule or commitment.

3.7.2.3 DAM_GOG Formulation

The calculation of DAM_GOG for an NQS *generation unit* not associated with a *pseudo-unit* is broken down into five components:

- Component 1: Any shortfall in payment on the DAM financially binding schedule for *energy* will be based upon the revenue received for that amount of *energy* committed in DAM in comparison with the cost represented in the DAM *offers* for *energy* and speed no-load offers;
- Component 2: Any shortfall in payment on the DAM financially binding schedule for *operating reserves* will be based upon the revenue received for that amount of *operating reserves* committed in DAM in comparison with the cost represented in the DAM *offers* for *operating reserve*;
- Component 3: The amount calculated by Component 1 up to MLP for the hours of MGBRT scheduled over midnight into the current *dispatch day*;
- Component 4: Any start-up offers to bring an offline *generation unit* through all the unit-specific start-up procedures, including synchronization and ramp up to MLP*;* and

- Component 5: Any DAM make-whole payment that was received as a result of being uneconomically scheduled by the DAM calculation engine.

The DAM_GOG will be calculated for each DAM commitment period for which a *generation unit* received a DAM financially binding schedule from the DAM calculation engine. A DAM commitment period is defined as a set of hours within a single *dispatch day* for which the *generation unit* has a contiguous DAM financial binding schedule up to the end of MGBRT or the end of PD commitment, whichever is greater.

An NQS *generation unit* can have multiple starts within a DAM *dispatch day*, and each start will be assessed separately. DAM_GOG will be calculated as:

$$DAM\_GOG = Max[0, Component\ 1 + Component\ 2 - Component\ 3 + Component\ 4 - Component\ 5\ ]$$

The operating status of the NQS *generation unit* at the time immediately preceding the DAM commitment will determine the component(s) that will be applicable in the calculation of DAM_GOG. There are three (3) variants that defines the operating status of the NQS *generation unit* in the DAM. The variants are defined as follows:

- Variant 1: If the NQS *generation unit* had a start in the current DAM *dispatch day* or was not injecting *energy* (i.e. was offline) in HE1 of the current DAM *dispatch day*, components 1, 2, 4 and 5 will be included in the calculation of DAM_GOG. Component 3 is not applicable because the *generation unit* was not injecting for the hours of MGBRT scheduled over midnight into the current *dispatch day*;
- Variant 2: If the NQS *generation unit* is scheduled in the previous DAM *dispatch day* to complete its MGBRT in the current DAM *dispatch day*, components 1, 2, 3 and 5 will be included in the calculation of DAM_GOG. Component 4 is not applicable because the start-up offer was included in the calculation for the previous *dispatch day*; and
- Variant 3: If the NQS *generation unit* is scheduled in the current DAM *dispatch day* HE1 after completing its MGBRT in HE24 of the previous DAM *dispatch day* or has DAM financially binding schedules in contiguous hours in excess of variant 2 hours, components 1, 2 and 5 will be included in the calculation of DAM_GOG. Component 3 is not applicable because the *generation unit* was not injecting *energy* for the hours of MGBRT scheduled over midnight into the current *dispatch day*. Component 4 is not applicable because the start-up offer was included in the calculation for the previous *dispatch day*.

These components will be calculated using the operating profit function described in Section 3.7.1 – DAM Make-Whole Payment (DAM_MWP) and in the *IESO market rules* Section 9.3.8A.2.

Component 1 – applicable to Variants 1, 2 and 3

Component 1 is the shortfall in payments, which is a result of the differences between the revenue earned for *energy* scheduled in DAM and the DAM *energy* and speed no-load offers for the DAM commitment period.

$$DAM\_COMP1^m_{k,h} = \sum^{H}\left[-1\ x\ \left(OP(DAM\_LMP^m_h, DAM\_QSI^m_{k,h}, DAM\_BE^m_{k,h})\right) + \ (DAM\_BE\_SNL^m_{k,h}\ x\ N^m_{k,h}/12)\right] - \sum^{RH}\left[DAM\_LMP^m_h\ x\ DAM\_QSI^m_{k,h}\right]$$

Where:

'H'	is the set of contiguous hours with DAM financially binding schedules from the start of MGBRT to the end of the DAM commitment period.
'RH'	is the set of contiguous hours with DAM financial binding schedules for the ramp-up period.
'$N_{k,h}^{m}$'	is the number of 5-minute intervals in *settlement hour* 'h' during which *delivery point* 'm' for *market participant* 'k' was synchronized and injecting *energy*.

Component 2 - applicable to Variants 1, 2 and 3

Component 2 is the shortfall in payments, which is a result of the differences between the revenue earned for *operating reserves* scheduled in DAM and the *operating reserve offers* for the DAM commitment period.

$$DAM\_COMP2_{k,h}^{m} = -1\ x \sum_{R}^{H} \left[OP\left(DAM\_PROR_{r,h}^{m}, DAM\_QSOR_{r,k,h}^{m}, DAM\_BOR_{r,k,h}^{m} \right) \right]$$

Where:

'R'	is the set of each class r of *operating reserve*.
'H'	is the set of contiguous hours with a DAM financially binding schedule for the DAM commitment period in question.

Component 3 – applicable to Variant 2

Component 3 is the amount calculated under Component 1 up to the *minimum loading point* for each hour that the NQS *generation unit* is scheduled by the DAM calculation engine over midnight into the current *dispatch day* to complete its MGBRT.

$$DAM\_COMP3_{k,h}^{m} = \sum^{H} [(-1)\ x\ \left(OP(DAM\_LMP_{h}^{m}, MLP_{k}^{m}, DAM\_BE_{k,h}^{m}) \right) + DAM\_BE\_SNL_{k,h}^{m} \times \frac{N_{k,h}^{m}}{12}]$$

Where:

'H'	is the set of contiguous hours with a DAM financially binding schedule for the DAM commitment period in question.
'MLP_{k}^{m}'	is the *minimum loading point* submitted by *market participant* 'k' for *delivery point* 'm'. In this instance, MLP refers to the previous DAM *trading day*.
'$N_{k,h}^{m}$'	is the number of 5-minute intervals in *settlement hour* 'h' during which *delivery point* 'm' for *market participant* 'k' was injecting *energy*.

Component 4 - applicable to Variant 1

Component 4 is the start-up offer incurred to bring an offline *generation unit* through all the unit-specific start-up procedures, including synchronization and ramp up to MLP.

The start-up offer will be adjusted depending on when the unit achieved MLP.

a. If MLP was achieved within the first six intervals of the first hour of its MGBRT or earlier as a result of being advanced by PD

$$DAM\_COMP4_{k,h}^{m} = DAM\_BE\_SU_{k,h}^{m}$$

b. If MLP was achieved within intervals 7 and 18 of the first two hours of the its MGBRT

$$DAM\_COMP4_{k,h}^{m} = DAM\_BE\_SU_{k,h}^{m} - (DAM\_BE\_SU_{k,h}^{m} \times N\_INT\ /12)$$

Where:

‘N_INT’ is the number of intervals between 7 and 18 that the resource achieved MLP.

c. If MLP was achieved after interval 18 of the first two hours of the its MGBRT

$$DAM\_COMP4_{k,h}^{m} = 0$$

DAM_GOG for an NQS *generation facility* for a DAM commitment period can be calculated for each variant as follows:

For variant 1: $DAM\_GOG_k^m = \ Max\left[0,\ DAM\_COMP1_k^m + DAM\_COMP2_k^m +\ DAM\_COMP4_{k,h}^m\right]$

For variant 2: $DAM\_GOG_k^m = \ Max[0,\ DAM\_COMP1_k^m + DAM\_COMP2_k^m - DAM\_COMP3_k^m]$

For variant 3: $DAM\_GOG_k^m = \ Max[0,\ DAM\_COMP1_k^m + DAM\_COMP2_k^m]$

Component 5 - applicable to Variants 1, 2 and 3

Component 5 is the sum of all DAM make-whole payments received by the NQS *generation unit* over the DAM commitment period.

$$DAM\_COMP5_k^m = \sum^{H} DAM\_MWP_{k,h}^m$$

Where:

‘H’ is set of contiguous hours with a DAM financially binding schedule for a DAM commitment period.

3.7.2.4 Pseudo-Unit Settlement – DAM_GOG Formulation

An NQS *generation unit* associated with a *pseudo-unit* will be eligible for a DAM_GOG provided it meets specific eligibility requirements. For the most part, the eligibility requirements for an NQS *generation unit* associated with a *pseudo-unit* and physical unit are relatively the same.

Eligibility for Recovery of Implied Cost of Start-Up Offers

A combustion turbine (CT) associated with a *pseudo-unit* will be eligible to recover its share of the PSU’s implied costs of any start-up offer, if:

- the CT synchronizes and comes online in real time;
- the CT attains its MLP in the first hour and a half of its DAM schedule or earlier as a result of being advanced by PD;
- the CT has completed its MGBRT;
- the DAM commitment does not immediately follow another commitment period under which the start-up offer is already guaranteed; and
- the CT’s single cycle flag is never activated during its MGBRT.

The steam turbine (ST) associated with one or more *pseudo-units* will be eligible to recover its share of the implied costs of any of its associated PSU’s start-up offers, if:

- at least one of the CT associated with the PSU has met all eligibility requirements.

Eligibility for Recovery of Implied Cost of Speed No-Load Offers

A combustion turbine associated with a *pseudo-unit* will be eligible to recover its share of the PSU's speed no-load offers for each hour of the DAM schedule that the CT actually produces *energy* for the entire hour. It will recover its share of a pro-rated speed no-load offer for each hour of that PSU's DAM schedule when the associated CT produces *energy* during some, but not all intervals within the hour.

3.7.2.5 Formulation

The DIPC and DIGQ for DAM_GOG will be calculated using the DAM PSU *energy offer* curves and the DAM scheduled quantities of those PSUs. For DAM_GOG, the DIGQ will be the sum of the ST portion of the PSU schedules from all PSUs where the associated CT is eligible for a DAM_GOG. As is the case for all other NQS *generation units*, the calculation of DAM_GOG for all NQS *generation units* associated with a *pseudo-unit* will be assessed across a period referred to as the DAM commitment period.

- For a CT associated with a PSU, each DAM commitment period is defined as a set of hours within a single *dispatch day* for which the associated PSU has a contiguous DAM financially binding schedule.
- For an ST associated with a PSU, each DAM commitment period is defined as a contiguous set of hours within a single *dispatch day* for which at least one of the associated PSUs has a DAM financially binding schedule.

CT Associated with a Pseudo-Unit

The calculation of DAM_GOG for an NQS *generation unit* CT associated with a PSU is broken down into the same five (5) components as the DAM_GOG for non-PSU NQS *generation units*, as further described in the component descriptions later in this section.

Each DAM commitment period at a CT shall be classified as one of three (3) variants, based on the operating status of the unit at the time immediately preceding it. The variant classification will determine which components will be included in the calculation of DAM_GOG for each DAM commitment period. The three variants are defined as follows:

- Variant 1: A DAM commitment period will be classified as Variant 1 if it is not immediately preceded by another DAM commitment period under which the start-up offer may be recovered.
  - o DAM_GOG for Variant 1 will include Components 1, 2, 4 and 5. Component 3 is not applicable because the PSU was not injecting for the hours of MGBRT scheduled over midnight into the current *dispatch day*.

$$DAM\_GOG_k^c = Max[0, DAM\_COMP1_k^c + DAM\_COMP2_k^c + DAM\_COMP4_k^c - DAM\_COMP4_k^c\ ]$$

- Variant 2: A DAM commitment period will be classified as Variant 2 if it begins in HE1 and the associated PSU was scheduled in the previous *dispatch day* to complete its MGBRT in the current DAM *dispatch day*.
  - o DAM_GOG for Variant 2 will include Components 1, 2, 3 and 5. Component 4 is not applicable because the start-up offer was included in the calculation for the previous *dispatch day*.

$$DAM\_GOG_k^c = Max[0, DAM\_COMP1_k^c + DAM\_COMP2_k^c - DAM\_COMP3_k^c - DAM\_COMP5_k^c]$$

- Variant 3: A DAM commitment period will be classified as Variant 3 if any one of the following is true:
  - The DAM commitment period begins in HE1; the previous DAM commitment period ended in HE24; and the associated PSU completed its MGBRT in the previous *dispatch day*.
  - There is a time-gap between the DAM generator commitment period and the previous DAM generator commitment period, but subsequently the associated PSU is committed by the PD engine to continue operating in the interim, thus avoiding the need to ramp down and start up again.
  - DAM_GOG for Variant 3 will include Components 1, 2 and 5. Component 3 is not applicable because the PSU was not injecting for the hours of MGBRT scheduled over midnight into the current *dispatch day*. Component 4 is not applicable because the start-up offer was included in the calculation for the previous *dispatch day*.

$$DAM\_GOG_k^c = Max[0, DAM\_COMP1_k^c + DAM\_COMP2_k^c - DAM\_COMP5_k^c]$$

Component 1 – applicable to Variants 1, 2 and 3

Component 1 is the shortfall in payment on the CT's share of its associated PSU's DAM financially binding schedule for *energy*. It is based upon the revenue received for that amount of *energy* in comparison with the cost represented in the CT's share of the associated PSU's DAM offers for *energy* and speed no-load for the DAM commitment period.

$$DAM\_COMP1_k^c = \sum^{H}\left[(-1)\ x\ OP(DAM\_LMP_h^c, DAM\_QSI_{k,h}^c, DAM\_QSI\_DIPC_{k,h}^c) + DAM\_BE\_SNL_{k,h}^p \times \frac{n_{k,h}^c}{12} \times \left(1 - ST\_Portion_{k,d1}^p\right)\right] - \sum^{RH}\left[DAM\_LMP_h^c \times DAM\_QSI_{k,h}^c\right]$$

Where:

'H'	is the set of contiguous hours that the CT 'c' has a DAM financially binding schedule at or above the CT's *minimum loading point* for the DAM commitment period in question.
'RH'	is the set of contiguous hours that the CT 'c' has a DAM financially binding schedule for the ramp-up period, scheduled above zero but below the CT's *minimum loading point*.
'p'	is the *pseudo-unit* associated with CT *delivery point* 'c'.
'$n_{k,h}^c$'	is the number of 5-minute intervals in *settlement hour* 'h' during which CT *delivery point* 'c' for *market participant* 'k' was synchronized and injecting *energy*.
'DIPC'	DAM variables with 'DIPC' are defined in Section 3.5.4 Table 3-17.
'$ST\_Portion_{k,d1}^p$'	as defined in Section 3.5.9 Table 3-37.

Component 2 – applicable to Variants 1, 2 and 3

Component 2 is the shortfall in payment on the CT's share of its associated PSU's DAM financially binding schedule for *operating reserves.* It is based upon the revenue received for that amount of *operating reserves* in comparison with the cost represented in the CT's share of the PSU's DAM *offers* for *operating reserves* for the DAM commitment period.

$$DAM\_COMP2_k^c = \sum^R \sum^H \left[(-1) \times OP\left(DAM\_PROR_{r,h}^c, DAM\_QSOR_{r,k,h}^c, DAM\_QSOR\_DIPC_{r,k,h}^c\right)\right]$$

Where:

'R'	is the set of each class r of *operating reserve.*
'H'	is the set of contiguous hours with a DAM financially binding schedule for the DAM commitment period in question.

Component 3 – applicable to Variant 2

Component 3 is the amount calculated under Component 1 for the CT share of the PSU's MLP for each hour in the current DAM commitment period in which the associated PSU was scheduled by the DAM calculation engine to complete its MGBRT for a DAM commitment started in the previous *dispatch day*.

$$DAM\_COMP3_k^c = \sum^K \left[(-1)x\ OP\left(DAM\_LMP_h^c, MLP_k^c, DAM\_QSI\_DIPC_{k,h}^c\right) + DAM\_BE\_SNL_{k,h}^p \times \frac{n_{k,h}^c}{12} \times \left(1 - ST\_Portion_{k,d1}^p\right)\right]$$

Where:

'K'	is the set of contiguous hours in the current CT DAM commitment period that are required to complete the associated PSU's MGBRT which began in the previous DAM *dispatch day*.
'p'	is the *pseudo-unit* associated with CT *delivery point* 'c'.
'MLP_k^c'	is the *minimum loading point* of CT *delivery point* 'c'.
'$n_{k,h}^c$'	is the number of 5-minute intervals in *settlement hour* 'h' during which CT *delivery point* 'c' for *market participant* 'k' was synchronized and injecting *energy*.
'DIPC'	DAM variables with 'DIPC' are defined in Section 3.5.4 Table 3-17.
'$ST\_Portion_{k,d1}^p$'	as defined in Section 3.5.9 Table 3-37.

Component 4 – applicable to Variant 1

Component 4 is the CT's share of the start-up offer to bring its associated PSU from offline through all the unit-specific start-up procedures, including synchronization and ramp up to *minimum loading point.* The level of guarantee provided may be adjusted depending on when the CT achieved MLP.

1. If the CT reached its MLP within the first six intervals of the first hour of the DAM commitment period:

$$DAM\_COMP4_k^c = DAM\_BE\_SU_{k,h}^p \times \left(1 - ST\_Portion_{k,d1}^p\right)$$

2. If the CT reached its MLP between the 7th and 18th intervals of its DAM commitment period:

$$DAM\_COMP4_k^c = DAM\_BE\_SU_{k,h}^p \times \left(1 - \frac{N\_INT}{12}\right) \times \left(1 - ST\_Portion_{k,d1}^p\right)$$

Where:

'N_INT'	is the number of intervals between 7 and 18 that the CT achieved its MLP.
'$\mathrm{ST\_Portion}_{k,d1}^{p}$'	as defined in Section 3.5.9 Table 3-37.

3. If MLP was not achieved within the first 18 intervals of its DAM generator commitment period:

$$DAM\_COMP4_k^c = 0$$

Component 5 – applicable to Variants 1, 2 and 3

Component 5 is the sum of all DAM make-whole payments received by the CT for hours included in its DAM commitment period.

$$DAM\_COMP5_k^c = \sum^H DAM\_MWP_{k,h}^c$$

Where:

'H'	is the set of contiguous hours that the CT 'c' has a DAM financially binding schedule at or above the CT's *minimum loading point* in the current DAM commitment period.

ST Associated with a Pseudo-Unit

The calculation of DAM_GOG for an NQS *generation unit* steam turbine associated with a *pseudo-unit* is broken down into the same five (5) components as the DAM_GOG for non-PSU NQS *generation units*, as further described later in this section.

Unlike that of its CT counterparts, an ST's DAM commitment period does not need to be assigned a variant classification. The DAM_GOG equations for an ST will apply under all possible scenarios. For any ST associated with one or more PSU's, the DAM_GOG for a given DAM commitment period for a *market participant* 'k' at ST *delivery point* 's' will be calculated as:

$$DAM\_GOG_k^s = Max[0, DAM\_COMP1_k^s + DAM\_COMP2_k^s - DAM\_COMP3_k^s + DAM\_COMP4_k^s - DAM\_COMP5_k^s\,]$$

Component 1

Component 1 is the shortfall in payment on the ST's share of all its associated PSUs' DAM financially binding *energy* schedules included in the ST's DAM commitment period. It is based upon the revenue received for that amount of *energy* in comparison with the cost represented in the ST's share of all associated PSU's DAM offers for *energy* and speed no-load for the DAM commitment period.

$$DAM\_COMP1_k^s = \sum^{H}\left[(-1) \times OP\left(DAM\_LMP_h^s, DAM\_QSI\_DIGQ_{k,h}^s, DAM\_QSI\_DIPC_{k,h}^s\right) + \sum_{p=1}^{M}\left(DAM\_BE\_SNL_{k,h}^p \times \frac{n_{k,h}^p}{12} \times ST\_Portion_{k,d1}^p\right)\right] - \sum^{RH}\left[DAM\_LMP_h^s \times DAM\_QSI_{k,h}^s\right]$$

Where:

‘H’	is the set of all hours in the ST’s DAM commitment period when at least one of the PSUs associated with ST has a DAM financially binding schedule at or above its respective PSU *minimum loading point*.
‘M’	is the set of all PSUs ‘p’ associated with ST ‘s’ that have a DAM financially binding schedule at or above their respective PSU *minimum loading point* in *settlement hour* ‘h’.
‘RH’	is the set of all hours in the ST’s DAM commitment period when the ST has a DAM financially binding schedule below its MLP for a 1x1 configuration.
‘$n_{k,h}^p$’	is the number of 5-minute intervals in *settlement hour* ‘h’ during which the CT associated with PSU ‘p’ for *market participant* ‘k’ was synchronized and injecting *energy*.
‘$ST\_Portion_{k,d1}^p$’	as defined in Section 3.5.9 Table 3-37.
‘DIPC’	DAM variables with ‘DIPC’ are defined in Section 3.5.4 Table 3-17
‘DIGQ’	DAM variables with ‘DIGQ’ are defined in Section 3.5.4 Table 3-17.

Component 2

Component 2 is the shortfall in payment on the ST’s share of all its associated PSU’s DAM financially binding *operating reserve* schedules included in the ST’s DAM commitment period. It is based upon the revenue received for that amount of *operating reserves* in comparison with the cost represented in the ST’s share of all associated PSU’s DAM offers for *operating reserves* for the DAM commitment period.

$$DAM\_COMP2_k^s = \sum^{R}\sum^{H}\left[(-1) \times OP\left(DAM\_PROR_{r,h}^s, DAM\_QSOR\_DIGQ_{r,k,h}^s, DAM\_QSOR\_DIPC_{r,k,h}^s\right)\right]$$

Where:

‘R’	is the set of each class r of *operating reserve*.
‘H’	is the set of all hours in the ST’s DAM commitment period when at least one of the PSUs associated with the ST has a DAM financially binding schedule at or above its respective PSU *minimum loading point*..
‘DIPC’	DAM variables with ‘DIPC’ are defined in Section 3.5.4 Table 3-17.
‘DIGQ’	DAM variables with ‘DIGQ’ are defined in Section 3.5.4 Table 3-17.

Component 3

Component 3 is the amount calculated under Component 1 for the ST share of *energy offers* up to MLP and speed no-load offers for any PSUs that were committed in the previous DAM *dispatch day* to complete their MGBRT during the current ST DAM commitment period.

$$DAM\_COMP3_k^s = \sum^{V}\sum^{K_p}\Big[(-1) \times OP\big(DAM\_LMP_h^s, \big(MLP_k^p \times ST\_Portion_{k,d1}^p\big), DAM\_BE_{k,h}^p\big) + DAM\_BE\_SNL_{k,h}^p \times \frac{n_{k,h}^p}{12} \times ST\_Portion_{k,d1}^p\Big]$$

Where:

'V'	is the set of all PSUs 'p' associated with ST 's', whose associated CT has a Variant 2 DAM commitment period that overlaps with the current ST DAM commitment period.
'K_p'	is the set of contiguous hours in the current ST DAM commitment period that are required to complete the MGBRT of PSU 'p' which began in the previous *dispatch day*.
'MLP_k^p'	is the *minimum loading point* of *pseudo-unit* 'p' for *market participant* 'k'.
'$n_{k,h}^p$'	is the number of 5-minute intervals in *settlement hour* 'h' during which the CT associated with PSU 'p' for *market participant* 'k' was synchronized and injecting *energy*.
'$ST\_Portion_{k,d1}^p$'	as defined in Section 3.5.9 Table 3-37.

Component 4

Component 4 is the ST's share of the start-up offers to bring any of its associated PSUs from offline through all the unit-specific start-up procedures, including synchronization and ramp up to *minimum loading point*, for any of its associated PSU's DAM financially binding commitments where the associated CT's DAM commitment period is eligible for start-up recovery. The level of guarantee provided may be adjusted depending on when the associated CTs achieved MLP.

$$DAM\_COMP4_k^s = \sum_{c=1}^{C}\sum_{x=1}^{X_c}\left[DAM\_COMP4_{k,x}^c \times \frac{ST\_Portion_{k,d1}^p}{\big(1 - ST\_Portion_{k,d1}^p\big)}\right]$$

Where:

'C'	is the set of all CTs 'c' associated with ST 's'.
'X_c'	is the set of all Variant 1 DAM commitment periods 'x' incurred by CT 'c' during the DAM commitment period of ST 's'.
'$DAM\_COMP4_{k,x}^c$'	is the DAM_GOG Component 4 quantity for each DAM commitment period 'x' of CT 'c', calculated exactly as outlined earlier in this document.
'$ST\_Portion_{k,d1}^p$'	as defined in Section 3.5.9 Table 3-37.

Component 5

Component 5 is the sum of all DAM make-whole payments received by the ST for hours included in its DAM commitment period.

$$DAM\_COMP5_k^s = \sum^{H} DAM\_MWP_{k,h}^s$$

Where:

‘H’	is the set of all hours in the ST’s DAM commitment period when at least one of the PSUs associated with the ST ‘s’ has with a DAM financially binding schedule at or above its respective PSU *minimum loading point*..

3.7.3 DAM_MWP Uplift (DAM_MWPU)

The DAM_MWP Uplift is intended to recover the cost of the DAM_MWP and DAM_GOG *settlement amounts* accrued.

The DAM_MWP Uplift will be allocated on a pro-rata basis to all *real-time market* loads and exports on a daily basis.

The formulation of the DAM_MWP Uplift is as follows:

$$DAM\_MWPU_k = \sum_{H}^{M} \Big(DAM\_MWP_{k,h}^{m} + DAM\_GOG_{k}^{m} - DAM\_MWP\_R_{k}^{m} \Big)\ x \left[\sum_{H}^{M,T} \left(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t} \right) / \sum_{K,H}^{M,T} \left(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t} \right) \right]$$

Where:

‘M’	is the set of all *delivery points* ‘m’ and *intertie metering points* ‘i’.
‘T’	is the set of all *metering intervals* ‘t’ in *settlement hour* ‘h’.
‘H’	is the set of all *settlement hours* ‘h’ in the *trading day*.
‘K’	is the set of all *market participants* ‘k’.
‘DAM_MWP_R’	is the total DAM_MWP made to NQS *generation facilities* and imports in the *reliability* scheduling pass.

3.7.4 DAM Reliability Scheduling Uplift (DRSU)

The purpose of the DAM Reliability Scheduling Uplift (DRSU) is to uplift the cost of DAM_MWP and DAM_GOG allocated to the following resources in the *reliability* scheduling pass of the DAM calculation engine:

- Additional NQS *generation units* committed; or
- Newly scheduled or incrementally scheduled imports.

The detailed description of *reliability* scheduling pass of the DAM calculation engine is provided in the DAM Calculation Engine detailed design document. Schedules in this pass will be compared to either the as-offered scheduling pass or, if applicable, the mitigated scheduling pass to identify the new or incremental schedules that are caused by the *reliability* scheduling pass. The DAM_MWP and DAM_GOG being generated by these schedules will be uplifted on a cost causation basis because resources that are committed in the *reliability* scheduling pass and might be uneconomic in subsequent passes because of the change in inputs from the *reliability* scheduling pass. The cost causation will allocate the uplift costs to those *market participants* specifically responsible for causing resources that are eligible for a make-whole payment to be scheduled. The new commitments made in the *reliability* scheduling pass cannot be de-committed in subsequent passes of the DAM calculation engine even if they are uneconomic and necessitate a DAM_MWP or DAM_GOG. This is the desired outcome of the DAM calculation engine passes because this ensures there are sufficient physical resources scheduled to meet *demand*.

Virtual supply transactions will be allocated a portion of the cost of DAM_MWP and DAM_GOG generated in the *reliability* pass of the DAM calculation engine for every MW cleared in the DAM. The remaining portion of the DRSU will be allocated proportionally to all real-time loads and exports. The DRSU will be distributed daily.

Price responsive loads will not be allocated a portion of the DRSU as originally determined in the DAM high-level design. The *IESO* does not expect the magnitude of *energy* being *bid* into the DAM for price responsive loads to be material relative to the magnitude of NDL being forecast by the *IESO*. If this changes in the future, the *IESO* will review this decision.

Table 3-58: Resolution of DAM Reliability Scheduling Uplift Calculation

Attribute	Resolution
Time resolution	Daily
Geographic resolution	Virtual Supply, Loads, and Exports: • By *virtual transaction zone, delivery point, and intertie metering point*
RT and DAM energy quantities	MW schedule values converted MWh values rounded to the nearest 0.1 MWh per hour or 0.001 MWh per 5-minute *metering interval*
All DAM and *real-time market settlement* data	Includes: Real-time *metering data* at applicable *delivery points*

There are no special considerations or exemptions.

3.7.4.1 Formulation

The DAM_MWP_R represents the DAM_GOG made to NQS *generation facilities* and DAM_MWP made to imports scheduled in the *reliability* scheduling pass of the DAM calculation engine.

In order to measure the impact of the *reliability* scheduling pass, the price from the final pass of the DAM calculation engine is used to calculate the make-whole payment.

The calculation uses the operating profit function described in Section 3.7.1: DAM Make-Whole Payment (DAM_MWP) and in *IESO market rules* Section 9.3.8A.2.

Pre-reliability scheduling pass:

$$PRE\_RSP\_Import\_DAM\_MWP^i_{k,h} = Max\left[0, DAM\_COMP1^i_{k,h} + DAM\_COMP2^i_{k,h}\right]$$

Where:

$$DAM\_COMP1^i_{k,h} = -1\ x\ \left[OP\left(DAM\_LMP^i_h, PRE\_RSP\_DAM\_QSI^i_{k,h}, DAM\_BE^i_{k,h}\right) - OP\left(DAM\_LMP^i_h, DAM\_EOP^i_{k,h}, DAM\_BE^i_{k,h}\right)\right]$$

$$DAM\_COMP2^i_{k,h} = -1\ x\ \sum_R \left\{ OP\left(DAM\_PROR^i_{r,h}, PRE\_RSP\_DAM\_QSOR^i_{r,k,h}, DAM\_BOR^i_{r,k,h}\right) - OP\left(DAM\_PROR^i_{r,h}, DAM\_EOP^i_{r,k,h}, DAM\_BOR^i_{r,k,h}\right)\right\}$$

Where:

'R' is the set of each class r of *operating reserve*.

'RSP'	DAM variables with 'RSP' are defined in Section 3.5.4 Table 3-14.
'EOP'	DAM variables with 'EOP' are defined in Section 3.5.4 Table 3-17.

During the *reliability* scheduling pass:

$$RSP\_Import\_DAM\_MWP^{i}_{k,h} = Max\left[0, DAM\_COMP1^{i}_{k,h} + DAM\_COMP2^{i}_{k,h}\right]$$

$$DAM\_COMP1^{i}_{k,h} = -1\ x\ \left[OP\left(DAM\_LMP^{i}_{h}, RSP\_DAM\_QSI^{i}_{k,h}, DAM\_BE^{i}_{k,h}\right) - OP\left(DAM\_LMP^{i}_{h}, DAM\_EOP^{i}_{k,h}, DAM\_BE^{i}_{k,h}\right)\right]$$

$$DAM\_COMP2^{i}_{k,h} = -1\ x\ \sum_{R}\left\{OP\left(DAM\_PROR^{i}_{r,h}, RSP\_DAM\_QSOR^{i}_{r,k,h}, DAM\_BOR^{i}_{r,k,h}\right) - OP\left(DAM\_PROR^{i}_{r,h}, DAM\_EOP^{i}_{r,k,h}, DAM\_BOR^{i}_{r,k,h}\right)\right\}$$

Where:

'R'	is the set of each class r of *operating reserve*.
'EOP'	DAM variables with 'EOP' are defined in Section 3.5.3 Table 3-16.
'RSP'	DAM variables with 'RSP' are defined in Section 3.5.3 Table 3-12.

$$DAM\_MWP\_R = \sum_{H,K}^{M} Max(RSP\_Import\_DAM\_MWP^{i}_{k,h} - PRE\_RSP\_Import\_DAM\_MWP^{i}_{k,h}, 0) + RSP\_New\_NQS\_DAM\_GOG^{m}_{k,h}$$

Where:

'M'	is the set of all *delivery points* 'm' and *intertie metering points* 'i'.
'H'	is the set of all *settlement* hours 'h' in the *trading day*.
'K'	is the set of all *market participants* 'k'.
'DAM_MWP_R'	is the total DAM_MWP made to NQS *generation facilities* and imports in the *reliability* scheduling pass
'RSP'	DAM variables with 'RSP' are defined in Section 3.5.4Table 3-14.

The DRSU will be allocated taking the following factors into consideration:

1. The scheduled quantity from all virtual supply *offers* that are scheduled in the DAM scheduling pass:

$$DAM\_QVSI^{v}_{k,h}$$

2. The *non-dispatchable load* in DAM that is over forecast in the *reliability* scheduling pass compared to the actual real-time *energy demand*:

$$DAM\_NDL\_OF^{m}_{k,h} = Max(DAM\_QSW^{m}_{k,h} - AQEW^{m,t}_{k,h}, 0)$$

The DAM_MWP_R will be allocated to the virtual supply first. The total measured quantity used in the uplift calculation for virtual supply *offers* will be the sum of the over forecasted *demand* and the DAM schedules for virtual supply *offers*, as follows:

$$DRSU_{k} = DAM\_MWP\_R\ x\ \sum_{H}^{V}(DAM\_QVSI^{v}_{k,h}) \ / \ \sum_{K,H}^{M,V}(DAM\_QVSI^{v}_{k,h} + DAM\_NDL\_OF^{m}_{k,h})$$

Where:

‘M’	is the set of all *delivery points* ‘m’ and *intertie metering points* ‘i’.
‘V’	is the set of all virtual transaction zonal trading entities ‘v’.
‘H’	is the set of all *settlement* hours ‘h’ in the *trading day*.
‘K’	is the set of all *market participants* ‘k’.

The DRSU remainder that is not allocated to virtual supply, will be allocated proportionally to loads and exports based on their real-time consumption:

$$DRSU\_Remainder_k = (DAM\_MWP\_R - DRSU)\ x \sum_{H}^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}) / \sum_{K,H}^{M} AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}$$

Where:

‘M’	is the set of all *delivery points* ‘m’ and *intertie metering points* ‘i’.
‘T’	is the set of all *metering intervals* ‘t’ in *settlement hour* ‘h’.
‘H’	is the set of *settlement hours* ‘h’ in the *trading day*.
‘K’	is the set of all *market participants* ‘k’.

3.7.5 Real-Time Make-Whole Payment (RT_MWP)

The *IESO* may instruct a unit to deviate from its economic operating point for *energy* or *operating reserve* in response to as manual control action or as a result of differences between the scheduling and pricing pass. In such cases, when the *market participant* responds to the *dispatch instructions*, the *market participant* might incur an implied loss of cost or an implied loss in profit. When this occurs, the *market participant* may receive compensation with a RT_MWP. The RT_MWP provides the incentive for *market participants* to follow their *dispatch instructions* for *energy* and *operating reserves* so that they do not incur a loss from operating below or above their economic operating point as a result of following the *IESO dispatch instructions*.

An implied loss or lost cost may occur when a unit is dispatched up by the *IESO* above its economic operating point where the *energy* cost or *operating reserve* cost is greater than the real-time price. RT_MWP for lost cost allows the *market participant* to recover the additional cost incurred above its economic operating point. MWs already covered by DAM will be excluded from the calculation of lost cost.

An implied loss in profit or lost opportunity cost may occur when a unit is dispatched down below its economic operating point. RT_MWP provides a compensation to a *market participant* for the lost opportunity to earn additional market revenue above its market cost to meet the *IESO dispatch instructions*.

RT_MWP will incorporate any required adjustment and mitigation tests into the calculation set out by the mitigation process, which is described in Section 3.13: Market Power Mitigation.

Table 3-59: Resolution of RT_MWP Calculations

Attribute	Resolution
Settlement time resolution	Hourly
Geographic resolution	*Facilities* within Ontario: • By *delivery point* *Intertie* transactions: • By *intertie metering point*
RT price accuracy(Energy and OR)	$/MWh to the nearest cent
All *real-time market settlement* data	• Real-time *metering data* at the *delivery points* to the nearest 0.001 MWh • Real-time schedule data at the *delivery points or intertie metering points* to the nearest 0.1 MWh • Real-time *offers* and *bids*

3.7.5.1 Eligibility

Eligibility - General

The eligibility of any *settlement amount* for RT_MWP is subject to the market integration events discussed in Section 3.5.7: Collection of Market Integration Data.

All dispatchable *generation facilities*, *boundary entities* and *dispatchable loads* are eligible for RT_MWP if they satisfy the eligibility criteria or are dispatched uneconomically in real time to meet a *reliability* need. However, the *IESO* may adjust or withhold RT_MWP if the *market participant* does not fully or accurately respond to the *IESO dispatch instructions*.

In addition, a *facility* will not be eligible for RT_MWP in any interval where:

- the unit is ramping up to meet its MLP or ramping down to come offline; or
- the unit has self-scheduled a portion of its MW such that it is unavailable for *dispatch*; or
- the unit is a *self-scheduling generation facility* or *intermittent generator*; or
- the unit was dispatched to prevent endangering the safety of any person, equipment damage, or violation of any *applicable law*; or
- the unit was dispatched down or dispatched up relative to its associated economic operating point at the request of the *market participant*.

Eligibility - Generation Unit with Minimum Daily Energy Limit

There are specific eligibility rules for hydroelectric *generation units* that are dispatched uneconomically in real time to meet a minimum daily *energy* limit (MinDEL). This type of hydroelectric *generation unit* will not be eligible to recover its as-offered cost for *energy* if:

- it is scheduled to supply *energy* across a *trading day* to meet only its minimum daily *energy* limit; or

- it is scheduled to supply *energy* across the day above its minimum daily *energy* limit. However, in combination with its minimum hourly outputs across the *trading day*, the unit achieves only its minimum daily *energy* limit.

Furthermore, this unit will not be compensated in the hours where it receives a schedule to supply *energy* at its minimum hourly must run; or for that portion of the *energy* schedule within or at the boundary of a *forbidden region*.

3.7.5.2 RT_MWP Formulation

Facilities that meet the eligibility criteria for RT_MWP will be able to recover lost cost and lost opportunity cost. A lost cost economic operating point and a lost opportunity cost economic operating point will be used to assess the RT_MWP. A distinction between the economic operating points is required as there can be overlaps between the two economic operating points. This is because the lost cost economic operating point (RT_LC_EOP) is determined solely based on *energy* or *operating reserve* costs relative to the real-time price whereas the lost opportunity cost economic operating point (RT_LOC_EOP) is determined based on a joint optimization of both the *energy* and *operating reserve* costs relative to the real-time price.

If a *facility* deviates in the opposite direction of both its lost cost economic operating point and real-time schedule, the lost cost component will be set to zero. This enables the *IESO* to compensate *market participants* only for eligible costs that were incurred because the *market participants* followed the *IESO dispatch instructions*.

For the purpose of calculating the lost opportunity cost, *market participant offers* and *bids* will be adjusted. The *energy offers* associated with a *generation facility* and *operating reserve offers* will be adjusted to the greater of the *offer* price and the associated *real-time market price*. Also, *bids* associated with loads will be adjusted to the lesser of *bid* price and the real-time price. This prevents the *IESO* from overcompensating *market participants* for lost opportunity costs that would have already been covered by the lost cost component for uneconomical *dispatch* schedules above the real-time price.

The calculation uses the operating profit function described in Section 3.7.1: DAM Make-Whole Payment (DAM_MWP) and in *IESO market rules* Section 9.3.8A.2.

RT_MWP for a *market participant* ‘k’ during *settlement hour* ‘h’ can be calculated as follows:

$$RT\_MWP_{k,h}^{m} = Max\left(0, ELC_{k,h}^{m} + ELOC_{k,h}^{m}\right) + Max(0, OLC_{k,h}^{m} + OLOC_{k,h}^{m})$$

Where:

‘$\mathrm{ELC}_{k,h}^{m}$’	is the total lost cost component of the RT_MWP for *market participant* ‘k’ at *delivery point* ‘m’ during *settlement hour* ‘h’ for *energy* attributed to the *facility* as a result of being dispatched up relative to its real-time lost cost economic operating point.
‘$\mathrm{ELOC}_{k,h}^{m}$’	is the total lost opportunity cost of the RT_MWP for *market participant* ‘k’ at *delivery point* ‘m’ during *settlement hour* ‘h’ for *energy*.
‘$\mathrm{OLC}_{k,h}^{m}$’	is the total lost cost component of the RT_MPW for *market participant* ‘k’ at *delivery point* ‘m’ during *settlement hour* ‘h’ for *operating reserves* attributed to the *facility* as a result of being dispatched up relative to its real-time lost cost economic operating point.
‘$\mathrm{OLOC}_{k,h}^{m}$’	is the total lost opportunity cost component of the RT_MWP for *market participant* ‘k’ at *delivery point* ‘m’ during *settlement hour* ‘h’ for *operating reserves.*

For a *generation unit*:

$$ELC_{k,h}^{m} = -1\ x \sum\nolimits_{T} Min\{0, [OP(RT\_LMP_{h}^{m,t}, Min(RT\_QSI_{k,h}^{m,t}, AQEI_{k,h}^{m,t}), BE_{k,h}^{m,t}) - OP(RT\_LMP_{h}^{m,t}, Max(RT\_LC\_EOP_{k,h}^{m,t}, DAM\_QSI_{k,h}^{m}/12), BE_{k,h}^{m,t})]\}$$

Where:

‘EOP’ RT variables with ‘EOP’ are defined in Section 3.5.6 Table 3-35.

During any *metering interval* ‘t’ within *settlement hour* ‘h’ in which the mathematical sign $RT\_QSI_{k,h}^{m,t}$ - $RT\_LC\_EOP_{k,h}^{m,t}$ is not equal to the mathematical sign $AQEI_{k,h}^{m,t}$ - $RT\_LC\_EOP_{k,h}^{m,t}$, the component $ELC_{k,h}^{m}$ shall be set to zero.

In order to calculate the component $ELOC_{k,h}^{m}$ for a *generation facility*, the *IESO* will adjust any *energy offer* price that is greater than the real-time *energy* price to the lesser of the *energy offer* price and the real-time *energy* price.

$$ELOC_{k,h}^{m} = \sum\nolimits_{m,t} \{OP(RT\_LMP_{h}^{m,t}, RT\_LOC\_EOP_{k,h}^{m,t}, BE_{k,h}^{m,t}) - Max[0, OP(RT\_LMP_{h}^{m,t}, Max(RT\_QSI_{k,h}^{m,t}, AQEI_{k,h}^{m,t}), BE_{k,h}^{m,t})]\}$$

Where:

‘EOP’ RT variables with ‘EOP’ are defined in Section 3.5.6 Table 3-35.

During any *metering interval* ‘t’ within *settlement hour* ‘h’ in which the mathematical sign $RT\_QSI_{k,h}^{m,t}$ - $RT\_LOC\_EOP_{k,h}^{m,t}$ is not equal to the mathematical sign $AQEI_{k,h}^{m,t}$ - $RT\_LOC\_EOP_{k,h}^{m,t}$, the component $ELOC_{k,h}^{m}$ shall be set to zero.

For a load:

$$ELC_{k,h}^{m} = \sum\nolimits_{m,t} \{OP(RT\_LMP_{h}^{m,t}, Min(RT\_QSW_{k,h}^{m,t}, AQEW_{k,h}^{m,t}), BL_{k,h}^{m,t}) - OP(RT\_LMP_{h}^{m,t}, Max(RT\_LC\_EOP_{k,h}^{m,t}, DAM\_QSW_{k,h}^{m}/12), BL_{k,h}^{m,t})\}$$

Where:

‘EOP’ RT variables with ‘EOP’ are defined in Section 3.5.6 Table 3-35.

During any *metering interval* ‘t’ within *settlement hour* ‘h’ in which the mathematical sign $RT\_QSW_{k,h}^{m,t}$ - $RT\_LC\_EOP_{k,h}^{m,t}$ is not equal to the mathematical sign $AQEW_{k,h}^{m,t}$ - $RT\_LC\_EOP_{k,h}^{m,t}$, the component $ELC_{k,h}^{m}$ shall be set to zero.

In order to calculate the component $ELOC_{k,h}^{m}$ for a *load facility*, the *IESO* will adjust any *bid* price that is lesser than the real-time *energy* price to the greater of the *bid* price and the real-time *energy* price.

$$ELOC_{k,h}^{m} = \sum\nolimits_{m,t} \{OP(RT\_LMP_{k,h}^{m,t}, RT\_LOC\_EOP_{k,h}^{m,t}, BL_{k,h}^{m,t}) - Max[0, OP(RT\_LMP_{k,h}^{m,t}, Max(RT\_QSW_{k,h}^{m,t}, AQEW_{k,h}^{m,t}), BL_{k,h}^{m,t})]\}$$

Where:

‘EOP’ RT variables with ‘EOP’ are defined in Section 3.5.6 Table 3-35.

During any *metering interval* ‘t’ within *settlement hour* ‘h’ in which the mathematical sign $RT\_QSW_{k,h}^{m,t}$ - $RT\_LOC\_EOP_{k,h}^{m,t}$ is not equal to the mathematical sign $AQEW_{k,h}^{m,t}$ - $RT\_LOC\_EOP_{k,h}^{m,t}$, the component $ELOC_{k,h}^{m}$ shall be set to zero.

This component may be positive or negative. A negative *settlement amount* may occur if both the *RT_LC_EOP* and the unit's *real-time schedule* exceed the *RT_LOC_EOP*.

For *operating reserve*:

$$OLC_{k,h}^{m} = -1\ x \sum_{r,m,t} \Big\{ OP\left(RT_{PROR}{}_{r,h}^{m,t}, RT_{QSOR}{}_{r,k,h}^{m,t}, BOR_{r,k,h}^{m,t}\right) - OP\left(RT_{PROR}{}_{r,h}^{m,t}, Max(RT_{OR_{LC_{EOP}}}{}_{r,k,h}^{m,t}, DAM_{QSOR}{}_{r,k,h}^{m}/12), BOR_{r,k,h}^{m,t}\right)\Big\}$$

Where:

'EOP' RT variables with 'EOP' are defined in Section 3.5.6 Table 3-35.

In order to calculate the component $OLOC_{k,h}^{m}$, the *IESO* will adjust any *operating reserve offer* price that is greater than the real-time *operating reserve* price to the lesser of the *operating reserve offer* price and the real-time *operating reserve* price.

$$OLOC_{k,h}^{m} = \sum_{r,m,t} \{OP\big(RT\_PROR_{r,h}^{m,t}, RT\_OR\_LOC\_EOP_{r,k,h}^{m,t}, BOR_{r,k,h}^{m,t}\big) - Max\big[0, OP\big(RT\_PROR_{r,h}^{m,t}, RT\_QSOR_{r,k,h}^{m,t}, BOR_{r,k,h}^{m,t}\big)\big]\}$$

Where:

'EOP' RT variables with 'EOP' are defined in Section 3.5.6 Table 3-35.

Boundary entities:

$$RT\_MWP_{k,h}^{i} = ELC_{k,h}^{i} + OLC_{k,h}^{i}$$

Where:

'$ELC_{k,h}^{i}$' is the total lost cost component of the RT_MWP for *market participant* 'k' at *intertie metering point* 'i' during *settlement hour* 'h' for *energy* attributed to the *facility* as a result of being dispatched up relative to its real-time lost cost economic operating point.

'$OLC_{k,h}^{i}$' is the total lost cost component of the RT_MWP for *market participant* 'k' at *intertie metering point* 'i' during *settlement hour* 'h' for *operating reserves* attributed to the *facility* as a result of being dispatched up relative to its real-time lost cost economic operating point.

For an import:

Real-time make-whole payments for imports are only applicable in the *operating reserve market* for lost cost. Any shortfall in payment on RT schedule for *operating reserves* will be based upon the revenue received for that amount of *operating reserves* scheduled in RT in comparison with the cost represented in the RT *operating reserve offers*.

$$OLC_{k,h}^{i} = \sum_{T,R}\{OP\big(ISPROR_{r,h}^{i,t}, Max(RT\_QSOR_{r,k,h}^{i,t}, DAM\_QSOR_{r,k,h}^{i}/12), BOR_{r,k,h}^{i,t}\big) - OP\big(ISPROR_{r,h}^{i,t}, Max(RT\_OR\_LC\_EOP_{r,k,h}^{i,t}, DAM\_QSOR_{r,k,h}^{i}/12), BOR_{r,k,h}^{i,t}\big)\}$$

Where:

'T' is the set of all *metering intervals* 't' in *settlement hour* 'h'.

'R' is the set of each class r of *operating reserve*.

'$ISPROR_{r,h}^{i,t}$' as defined in Section 3.5.6 Table 3-27.

‘EOP’ RT variables with ‘EOP’ are defined in Section 3.5.6 Table 3-35.

For an export where there is a PD pricing discrepancy:

Real-time make-whole payments for exports are only applicable in the *energy market* for lost cost. An export will be compensated for its loss when an export is scheduled with a lost cost in the latest pre-dispatch, and the price at the interface in both the latest pre-dispatch and real-time exceeds the transaction’s *bid* cost.

$$ELC_{k,h}^{i} = \sum_{T}\{OP(Min(ISP_{h}^{i,t}, PD\_LMP_{h}^{i}), Max(SQEW_{k,h}^{i,t}, DAM\_QSW_{k,h}^{i}/12), BL_{k,h}^{i,t}) - OP(Min(ISP_{h}^{i,t}, PD\_LMP_{h}^{i}), Max(RT\_LC\_EOP_{k,h}^{i,t}, DAM\_QSW_{k,h}^{i}/12), BL_{k,h}^{i,t})\}$$

Where:

‘T’ is the set of all *metering intervals* ‘i’ in *settlement hour* ‘h’.

‘$ISP_{h}^{i,t}$’ as defined in Section 3.5.6 Table 3-27.

‘EOP’ RT variables with ‘EOP’ are defined in Section 3.5.6 Table 3-35.

For an export where there is a manual *dispatch* out of merit:

When there is a manual *dispatch* out of merit, the export transaction will be eligible for a lost cost RT_MWP.

$$ELC_{k,h}^{i} = \sum_{T}\{OP(ISP_{h}^{i,t}, Max(SQEW_{k,h}^{i,t}, DAM\_QSW_{k,h}^{i}/12), BL_{k,h}^{i,t}) - OP(ISP_{h}^{i,t}, Max(RT\_LC\_EOP_{k,h}^{i,t}, DAM\_QSW_{k,h}^{i}/12), BL_{k,h}^{i,t})\}$$

Where:

‘T’ is the set of all *metering intervals* ‘i’ in *settlement hour* ‘h’.

‘$ISP_{h}^{i,t}$’ as defined in Section 3.5.6 Table 3-27.

‘EOP’ RT variables with ‘EOP’ are defined in Section 3.5.6 Table 3-35.

3.7.5.3 Pseudo-Unit Settlement – RT_MWP Formulation

Physical *generation units* associated with *pseudo-units* will be eligible to receive RT_MWP compensation subject to the following eligibility criteria:

- For a CT associated with a PSU, RT_MWP will be calculated for all *metering intervals* that the CT is scheduled to inject at or above its MLP in real-time. *Metering intervals* where the CT is ramping up to meet its MLP or ramping down to come offline, and therefore cannot be dispatched up or down, will not be eligible for RT_MWP.
- For an ST associated with a PSU, RT_MWP will be calculated for all *metering intervals* where at least one of the CTs associated with the ST is scheduled above its MLP in real-time.

CT Associated with a Pseudo-Unit

CTs that meet the eligibility criteria for RT_MWP will be able to recover their lost cost and lost opportunity cost. Calculation of RT_MWP for a CT associated with a PSU will require a derived interval price curve (DIPC) for *energy* and for each class of *operating reserve*, in each *metering interval* that the eligibility criteria was met.

For the CT, the *energy* DIPC referred to as RT_MWP_DIPC will be derived from the real-time *energy offers* for the corresponding PSU, using the greater of RT_QSI and RT_LC_EOP as the quantity input. The same DIPC can be used in all of the operating profit calculations required for RT_MWP. For each class of *operating reserve*, the OR DIPC referred to as the OR_RT_MWP_DIPC will be derived from the real-time *operating reserve offers* for the corresponding PSU, using the greater of RT_QSOR and RT_OR_LC_EOP.

RT_MWP for *market participant* 'k' at combustion turbine *delivery point* 'c' during *settlement hour* 'h' is calculated as follows:

$$RT\_MWP_{k,h}^{c} = Max\left(0, ELC_{k,h}^{c} + ELOC_{k,h}^{c}\right) + Max\left(0, OLC_{k,h}^{c} + OLOC_{k,h}^{c}\right)$$

Where:

'$\mathrm{ELC}_{k,h}^{c}$' is the total lost cost component of the RT_MWP for *market participant* 'k' at combustion turbine *delivery point* 'c' during *settlement hour* 'h' for *energy* attributed to the *facility* as a result of being dispatched up relative to its real-time lost cost economic operating point (EOP).

'$\mathrm{ELOC}_{k,h}^{c}$' is the total lost opportunity cost component of the RT_MWP for *market participant* 'k' *at* combustion turbine *delivery point* 'c' during *settlement hour* 'h' for *energy*.

'$\mathrm{OLC}_{k,h}^{c}$' is the total lost cost component of the RT_MWP for *market participant* 'k' at combustion turbine *delivery point* 'c' during *settlement hour* 'h' for *operating reserves* attributed to the *facility* as a result of being dispatched up relative to its real-time lost cost economic operating point.

'$\mathrm{OLOC}_{k,h}^{c}$' is the total lost opportunity cost component of the RT_MWP for *market participant* 'k' at combustion turbine *delivery point* 'c' during *settlement hour* 'h' for *operating reserves.*

$$ELC_{k,h}^{c} = (-1) \times \sum^{T} Min\Big\{0, \Big[OP\Big(RT\_LMP_{h}^{c,t}, Min\big(RT\_QSI_{k,h}^{c,t}, AQEI_{k,h}^{c,t}\big), RT\_MWP\_DIPC_{k,h}^{c,t}\Big) - OP\Big(RT\_LMP_{h}^{c,t}, Max\big(RT\_LC\_EOP_{k,h}^{c,t}, DAM\_QSI_{k,h}^{c}/12\big), RT\_MWP\_DIPC_{k,h}^{c,t}\Big)\Big]\Big\}$$

Where:

'T' is the set of all *metering intervals* 't' in *settlement hour* 'h' when the real-time schedule for *energy* at CT *delivery point* 'c' is greater than the CT *minimum loading point.*

'DIPC' RT variables with 'DIPC' are defined in Section 3.5.6 Table 3-35.

'EOP' RT variables with 'EOP' are defined in Section 3.5.6 Table 3-35.

During any metering interval 't' within settlement hour 'h' in which the mathematical sign of $RT\_QSI_{k,h}^{c,t} - RT\_LC\_EOP_{k,h}^{c,t}$ is not equal to the mathematical sign of $AQEI_{k,h}^{c,t} - RT\_LC\_EOP_{k,h}^{c,t}$, the component $ELC_{k,h}$ shall be set to zero.

In order to calculate the component $ELOC_{k,h}^{c}$ for a CT *generation facility*, any *energy offer* price in the derived *energy offer* curve $RT\_MWP\_DIPC_{k,h}^{c,t}$ that is greater than the real-time *energy* price $RT\_LMP_{h}^{c,t}$ will be reduced to that real-time *energy* price.

$$ELOC_{k,h}^{c} = \sum^{T} \Big\{OP\Big(RT\_LMP_{h}^{c,t}, RT\_LOC\_EOP_{k,h}^{c,t}, RT\_MWP\_DIPC_{k,h}^{c,t}\Big) - Max\Big[0, OP\Big(RT\_LMP_{h}^{c,t}, Max\big(RT\_QSI_{k,h}^{c,t}, AQEI_{k,h}^{c,t}\big), RT\_MWP\_DIPC_{k,h}^{c,t}\Big)\Big]\Big\}$$

Where:

‘T’ is the set of all *metering intervals* ‘t’ in *settlement hour* ‘h’ when the real-time schedule for *energy* at CT *delivery point* ‘c’ is greater than the CT *minimum loading point*.

‘DIPC’ RT variables with ‘DIPC’ are defined in Section 3.5.6 Table 3-35.

This component may be positive or negative. A negative *settlement amount* may occur if both the RT_LC_EOP and the unit’s real-time schedule exceed the RT_LOC_EOP.

During any *metering interval* ‘t’ within *settlement hour* ‘h’ in which the mathematical sign of $RT\_QSI_{k,h}^{c,t} - RT\_LOC\_EOP_{k,h}^{c,t}$ is not equal to the mathematical sign of $AQEI_{k,h}^{c,t} - RT\_LOC\_EOP_{k,h}^{c,t}$, the component $ELOC_{k,h}^{c}$ shall be set to zero.

$$OLC_{k,h}^{c} = (-1) \times \sum_{R}^{T} \{OP(RT\_PROR_{r,h}^{c,t}, RT\_QSOR_{r,k,h}^{c,t}, OR\_RT\_MWP\_DIPC_{r,k,h}^{c,t}) - OP(RT\_PROR_{r,h}^{c,t}, Max(RT\_OR\_LC\_EOP_{r,k,h}^{c,t}, DAM\_QSOR_{r,k,h}^{c}/12), OR\_RT\_MWP\_DIPC_{r,k,h}^{c,t})\}$$

Where:

‘T’ is the set of all *metering intervals* ‘t’ in *settlement hour* ‘h’ when the real-time schedule for *energy* at CT *delivery point* ‘c’ is greater than the CT *minimum loading point*.

‘R’ is the set of each class r of *operating reserve*.

‘DIPC’ RT variables with ‘DIPC’ are defined in Section 3.5.6 Table 3-35.

‘EOP’ RT variables with ‘EOP’ are defined in Section 3.5.6 Table 3-35.

In order to calculate the component $OLOC_{k,h}^{c}$ for a CT *generation facility*, any *operating reserve offer* price in the any of the derived *operating reserve offer* curves $OR\_RT\_MWP\_DIPC_{r,k,h}^{c,t}$ that is greater than the real-time price $RT\_PROR_{r,h}^{c,t}$ for that particular class of *operating reserve* will be reduced to that real-time price.

$$OLOC_{k,h}^{c} = \sum_{R}^{T} \{OP(RT\_PROR_{r,h}^{c,t}, RT\_OR\_LOC\_EOP_{r,k,h}^{c,t}, OR\_RT\_MWP\_DIPC_{r,k,h}^{c,t}) - Max[0, OP(RT\_PROR_{r,h}^{c,t}, RT\_QSOR_{r,k,h}^{c,t}, OR\_RT\_MWP\_DIPC_{r,k,h}^{c,t})]\}$$

Where:

‘T’ is the set of all *metering intervals* ‘t’ in *settlement hour* ‘h’ when the real-time schedule for *energy* at CT *delivery point* ‘c’ is greater than the CT *minimum loading point*.

‘R’ is the set of each class r of *operating reserve*.

‘DIPC’ RT variables with ‘DIPC’ are defined in Section 3.5.6 Table 3-35.

‘EOP’ RT variables with ‘EOP’ are defined in Section 3.5.6 Table 3-35.

ST Associated with a Pseudo-Unit

STs that meet the eligibility criteria for RT_MWP will be able to recover their lost cost and lost opportunity cost. Calculation of RT_MWP for an ST associated with a PSU will require a derived interval price curve (DIPC) for *energy* and for each class of *operating reserve*, in each *metering interval* that the eligibility criteria was met.

The RT_MWP_DIPC for *energy* for the ST will be derived from the real-time *energy offers* for each associated PSU whose CT meets the eligibility criteria for RT_MWP. It will use the greater of RT_QSI and RT_LC_EOP as the quantity input for each eligible PSU. The CT will be eligible for

RT_MWP in a *metering interval* if it is scheduled to inject *energy* at or above its MLP in that *metering interval*.

The OR_RT_MWP_DIPC for the ST will be derived for each class of *operating reserve*, from the real-time *operating reserve offers* for each associated PSU, using the greater of RT_QSOR and RT_OR_LC_EOP.

The calculation of RT_MWP for the ST will require a derived interval guaranteed quantity (DIGQ) for the real-time schedule for *energy*. This DIGQ variable, referred to as RT_QSI_DIGQ, is derived by summing the ST portions of the real-time PSU schedule for each PSU whose associated CT meets the eligibility criteria for RT_MWP in that *metering interval*. Again, the CT will be eligible for RT_MWP in a *metering interval* if it is scheduled to inject *energy* at or above its MLP in that *metering interval*.

RT_MWP for an ST associated with a PSU will also utilize the variable DAM_QSI_DIGQ, which is used in DAM_MWP and DAM_GOG as well. DAM_QSI_DIGQ is calculated by summing the ST portions of the DAM schedule for each associated PSU that has a DAM financially binding schedule above MLP in a given *settlement hour*.

The eligibility requirement on associated PSUs in the formulation of RT_MWP_DIPC and RT_QSI_DIGQ serves to remove any contributions of PSUs that are ramping up or ramping down.

RT_MWP for *market participant* 'k' at steam turbine *delivery point* 's' during *settlement hour 'h'* is calculated as follows:

$$RT\_MWP_{k,h}^{s} = Max\left(0, ELC_{k,h}^{s} + ELOC_{k,h}^{s}\right) + Max\left(0, OLC_{k,h}^{s} + OLOC_{k,h}^{s}\right)$$

Where:

'$\mathrm{ELC}_{k,h}^{s}$'	is the total lost cost component of the RT_MWP for *market participant* 'k' at steam turbine *delivery point* 's' during *settlement hour* 'h' for *energy* attributed to the *facility* as a result of being dispatched up relative to its real-time lost cost economic operating point (EOP).
'$\mathrm{ELOC}_{k,h}^{s}$'	is the total lost opportunity cost component of the RT_MWP for *market participant* 'k' *at* steam turbine *delivery point* 's' during *settlement hour* 'h' for *energy*.
'$\mathrm{OLC}_{k,h}^{s}$'	is the total lost cost component of the RT_MWP for *market participant* 'k' at steam turbine *delivery point* 's' during *settlement hour* 'h' for *operating reserves* attributed to the *facility* as a result of being dispatched up relative to its real-time lost cost economic operating point.
'$\mathrm{OLOC}_{k,h}^{s}$'	is the total lost opportunity cost component of the RT_MWP for *market participant* 'k' at steam turbine *delivery point* 's' during *settlement hour* 'h' for *operating reserves.*

$$ELC_{k,h}^{s} = (-1) \times \sum^{T} Min\{0, [OP\left(RT\_LMP_{h}^{s,t}, Min\left(RT\_QSI\_DIGQ_{k,h}^{s,t}, AQEI_{k,h}^{s,t}\right), RT\_MWP\_DIPC_{k,h}^{s,t}\right) - OP\left(RT\_LMP_{h}^{s,t}, Max\left(RT\_LC\_EOP_{k,h}^{s,t}, DAM\_QSI\_DIGQ_{k,h}^{s}/12\right), RT\_MWP\_DIPC_{k,h}^{s,t}\right)]\}$$

Where:

'T'	is the set of all *metering intervals* 't' in *settlement hour* 'h' when at least one CT associated with the ST has a real-time schedule for *energy* at or above *minimum loading point.*
'DIPC'	RT variables with 'DIPC' are defined in Section 3.5.6 Table 3-35
'DIGQ'	DAM variables with 'DIGQ' are defined in Section 3.5.4 Table 3-17.

RT variables with ‘DIGQ’ are defined in Section 3.5.6 Table 3-35.

‘EOP’ RT variables with ‘EOP’ are defined in Section 3.5.6 Table 3-35.

During any *metering interval* ‘t’ within *settlement hour* ‘h’ in which the mathematical sign of $RT\_QSI\_DIGQ^{s,t}_{k,h} - RT\_LC\_EOP^{s,t}_{k,h}$ is not equal to the mathematical sign of $AQEI^{s,t}_{k,h} - RT\_LC\_EOP^{s,t}_{k,h}$, the component $ELC^{s}_{k,h}$ shall be set to zero.

The ST’s metered AQEI cannot be altered to remove any contributions of PSUs that are ramping up or ramping down in a given *metering interval*. Therefore, the variable AQEI in the term $Max\left(RT\_QSI\_DIGQ^{s,t}_{k,h}, AQEI^{s,t}_{k,h}\right)$ used for other *generation unit* types for the ELOC quantity input may be incorrect, leading to a reduced amount for the lost opportunity cost component. For this reason, a different structure is required for the ST.

The equation for ELOC will split up the *metering intervals* in each hour into two sets. The first set ‘T_0’ will include all *metering intervals* when none of the ST’s associated CTs are ramping up or ramping down. The second set ‘T_1’ will include all *metering intervals* when one or more of the associated CTs are ramping up or ramping down.

In order to calculate the component $ELOC^{s}_{k,h}$ for a ST *generation unit*, any *energy offer* price in the derived *energy offer* curve $RT\_MWP\_DIPC^{s,t}_{k,h}$ that is greater than the real-time *energy* price $RT\_LMP^{s,t}_{h}$ will be reduced to that real-time *energy* price.

This component may be positive or negative. A negative *settlement amount* may occur if both the RT_LC_EOP and the unit’s real-time schedule exceed the RT_LOC_EOP.

$$
\begin{aligned}
ELOC^{s}_{k,h} = \sum\nolimits^{T_0} \Big\{ & OP\left(RT\_LMP^{s,t}_{h}, RT\_LOC\_EOP^{s,t}_{k,h}, RT\_MWP\_DIPC^{s,t}_{k,h}\right) \\
& - Max\left[0, OP\left(RT\_LMP^{s,t}_{h}, Max\left(RT\_QSI\_DIGQ^{s,t}_{k,h}, AQEI^{s,t}_{k,h}\right), RT\_MWP\_DIPC^{s,t}_{k,h}\right)\right]\Big\} \\
& + \sum\nolimits^{T_1} \Big\{ OP\left(RT\_LMP^{s,t}_{h}, RT\_LOC\_EOP^{s,t}_{k,h}, RT\_MWP\_DIPC^{s,t}_{k,h}\right) \\
& - Max\left[0, OP\left(RT\_LMP^{s,t}_{h}, RT\_QSI\_DIGQ^{s,t}_{k,h}, RT\_MWP\_DIPC^{s,t}_{k,h}\right)\right]\Big\}
\end{aligned}
$$

Where:

‘T_0’ is the set of all *metering intervals* ‘t’ in *settlement hour* ‘h’ when at least one CT associated with the ST has a real-time schedule for *energy* at or above *minimum loading point*, and none of the CTs associated with the ST have a real-time schedule that is below MLP.

‘T_1’ is the set of all *metering intervals* ‘t’ in *settlement hour* ‘h’ when (1) at least one CT associated with the ST has a real-time schedule at or above *minimum loading point*, and (2) one or more of the CTs associated with the ST have a real-time schedule that is below MLP.

‘DIPC’ RT variables with ‘DIPC’ are defined in Section 3.5.6 Table 3-35.

‘DIGQ’ RT variables with ‘DIGQ’ are defined in Section 3.5.6 Table 3-35.

‘EOP’ RT variables with ‘EOP’ are defined in Section 3.5.6 Table 3-35.

$$
\begin{aligned}
& OLC^{s}_{k,h} \\
& = (-1) \\
& \times \sum\nolimits_{R}^{T} \Big\{ OP\left(RT\_PROR^{s,t}_{r,h}, RT\_QSOR^{s,t}_{r,k,h}, OR\_RT\_MWP\_DIPC^{s,t}_{r,k,h}\right) \\
& - OP\left(RT\_PROR^{s,t}_{r,h}, Max\left(RT\_OR\_LC\_EOP^{s,t}_{r,k,h}, DAM\_QSOR^{s}_{r,k,h}/12\right), OR\_RT\_MWP\_DIPC^{s,t}_{r,k,h}\right)\Big\}
\end{aligned}
$$

Where:

'T'	is the set of all *metering intervals* 't' in *settlement hour* 'h' when at least one CT associated with the ST has a real-time schedule for *energy* at or above *minimum loading point.*
'R'	is the set of each class r of *operating reserve*.
'DIPC'	RT variables with 'DIPC' are defined in Section 3.5.6 Table 3-35.
'EOP'	RT variables with 'EOP' are defined in Section 3.5.6 Table 3-35.

In order to calculate the component $OLOC_{k,h}^{s}$ for a ST *generation facility*, any *operating reserve offer* price in any of the derived *operating reserve offer* curves $OR\_RT\_MWP\_DIPC_{r,k,h}^{s,t}$ that is greater than the real-time price $RT\_PROR_{r,h}^{s,t}$ for that particular class of *operating reserve* will be reduced to that real-time price.

$$OLOC_{k,h}^{s} = \sum_{R}^{T}\{OP(RT\_PROR_{r,h}^{s,t}, RT\_OR\_LOC\_EOP_{r,k,h}^{s,t}, OR\_RT\_MWP\_DIPC_{r,k,h}^{s,t}) - Max[0, OP(RT\_PROR_{r,h}^{s,t}, RT\_QSOR_{r,k,h}^{s,t}, OR\_RT\_MWP\_DIPC_{r,k,h}^{s,t})]\}$$

Where:

'T'	is the set of all *metering intervals* 't' in *settlement hour* 'h' when at least one CT associated with the ST has a real-time schedule for *energy* at or above *minimum loading point.*
'R'	is the set of each class r of *operating reserve*.
'DIPC'	RT variables with 'DIPC' are defined in Section 3.5.6 Table 3-35.
'EOP'	RT variables with 'EOP' are defined in Section 3.5.6 Table 3-35.

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

The real-time make-whole payment uplift (RT_MWPU) is intended to recover the cost of the RT_MWP *settlement amounts* accrued in the *real-time market*.

The RT_MWPU is allocated on a pro-rata basis to all *real-time market* loads and exports on an hourly basis.

The formulation of the RT_MWP Uplift is as follows:

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

Where:

'K'	is the set of all *market participants* 'k'.
'M'	is the set of all *delivery points* 'm' and *intertie metering points* 'i'.
'T'	is the set of all *metering intervals* 't' in *settlement hour* 'h'.
'$RQ_{k,h}^{m,i,t}$'	as defined in Section 3.5.6 Table 3-36.

3.7.7 DAM Balancing Credit (DAM_BC)

Under certain circumstances, a *market participant* with a DAM financially binding schedule may incur a financial loss as a result of an *IESO* control action on *energy* and *operating reserve* in real time. When this occurs, the *IESO* will provide a DAM Balancing Credit (DAM_BC) to cover any operating loss incurred as a result of following *dispatch instructions*. DAM_BC provides an offset against any negative impact of real-time balancing due to a system *reliability* need. However, it does not provide a guarantee of the operating profit.

A *market participant* may incur a financial loss when the *IESO* cancels a *generation unit* commitment due to a system *reliability* need after the *generation unit* has received a DAM commitment. A *market participant* who does not submit *offers* in real time and is ineligible for RT_MWP may incur a financial loss when the *IESO* curtails a resource due to a system *reliability* need after the resource has received a DAM financially binding schedule. A *boundary entity* may incur a financial loss as a result of a negative buyback of its day-ahead position when the *IESO* activates *operating reserves* or when a transaction is curtailed as a result of system *reliability*. DAM_BC will incorporate any required adjustment and mitigation test results into the calculation set out by the market power mitigation process, which is described in Section Market Power Mitigation: Market Power Mitigation.

Table 3-60: Resolution of DAM_BC Calculations

Attribute	Resolution
Settlement time resolution	Hourly
Geographic resolution	*Generation facilities* within Ontario: • By *delivery point* *Intertie* transactions: • By *intertie metering point*
Day-ahead *settlement* data	Real-time *metering data* at the *delivery points* or *intertie metering points*
All *real-time market settlement* data	• Real-time *metering data* at the *delivery points* or *intertie metering points* • Real-time schedule data at the *delivery points or intertie metering points* • Real-time *offers* and *bids* • Real-time nodal price

A *market participant* will not be eligible for DAM_BC in any hour in which:

- the *facility* fails to respond or does not follow the *dispatch instructions*; or
- the *facility* was dispatched, on request from *market participant*, to prevent endangering the safety of any person, equipment damage, or violation of any *applicable law*.

3.7.7.1 DAM_BC Formulation

The calculation uses the operating profit function described in Section 3.7.1: DAM Make-Whole Payment (DAM_MWP) and in *IESO market rules* Section 9.3.8A.2.

DAM_BC will apply in real time when the *IESO* curtails a *generation unit* due to a system *reliability* need after the *generation unit* has received a DAM financially binding schedule. DAM_BC for a *market participant* ‘k’ for a *delivery point* ‘m’ during *settlement hour* ‘h’ can be calculated as follows:

$$DAM\_BC_{k,h}^{m} = BCE_{k,h}^{m} + BCOR_{k,h}^{m}$$

For *generation facilities*:

Balancing Credit for *Energy*:

$$BCE_{k,h}^{m} = MAX\left\{0, \sum^{T}\left(RT\_LMP_{h}^{m,t} - DAM\_LMP_{h}^{m}\right)\right\} \times MAX\left\{0, \sum^{T}\left(DAM\_QSI_{k,h}^{m}/12 - RT\_QSI_{k,h}^{m,t}\right)\right\}$$

Where:

‘M’	is the set of all *delivery points* ‘m’.
‘T’	is the set of all *metering intervals* ‘t’ in *settlement hour* ‘h’.

Balancing Credit for *Operating Reserve*:

$$BCOR_{k,h}^{m} = \sum^{R} MAX\left\{0, \sum^{T}\left(RT\_PROR_{r,h}^{m,t} - DAM\_PROR_{r,h}^{m}\right)\right\} \times MAX\left\{0, \sum^{T}\left(DAM\_QSOR_{r,k,h}^{m}/12 - RT\_QSOR_{r,k,h}^{m,t}\right)\right\}$$

Where:

‘M’	is the set of all *delivery points* ‘m’.
‘T’	is the set of all *metering intervals* ‘t’ in *settlement hour* ‘h’.
‘R’	is the set of each class r of *operating reserve.*

For *boundary entities*:

DAM_BC will apply in real time when the *IESO* curtails any transaction, due to a system *reliability* need, causing the *intertie* transaction to be dispatched down relative to its DAM position and is scheduled to less than its economic operating point in real-time. DAM_BC for *boundary entities* for *market participant* ‘k’ for an *intertie metering point* ‘i’ during *settlement hour* ‘h’ can be calculated as follows:

$$DAM\_BC_{k,h}^{i} = BCE_{k,h}^{i} + BCOR_{k,h}^{i}$$

Imports:

DAM_BC applies when the *intertie* settlement price (ISP) is higher than the DAM_LMP for the applicable import. If the participant’s real-time *offer* is at a higher price than the DAM_LMP, DAM_BC will be reduced by the increased costs represented by the RT *offer*.

Balancing Credit for *Energy*:

$$BCE_{k,h}^{i} = Max\{0, \sum^{T} (Min(RT\_LOC\_EOP_{k,h}^{i,t}, DAM\_QSI_{k,h}^{i}/12) - SQEI_{k,h}^{i,t}) \times (ISP_{h}^{i,t} - DAM\_LMP_{h}^{i,}) + OP(DAM\_LMP_{h}^{i}, Min(RT\_LOC\_EOP_{k,h}^{i,t}, DAM\_QSI_{k,h}^{i}/12), BE_{k,h}^{i,t})\}$$

Where:

'I'	is the set of all *intertie metering points* 'i'.
'T'	is the set of all *metering intervals* 't' in *settlement hour* 'h'.
'EOP'	RT variables with 'EOP' are defined in Section 3.5.6 Table 3-35.
'$ISP_h^{i,t}$'	as defined in Section 3.5.6 Table 3-27.

Rule: BE represents the RT *offer* of the *market participant* adjusted for the DAM_BC. When the *offer* price in any of the N by 2 matrix of the *price-quantity pairs* is less than the DAM_LMP, it will be replaced by the DAM_ LMP.

Balancing Credit for *Operating Reserve:*

$$BCOR_{k,h}^{i} = \sum^{R} Max\{0, \sum^{T} (Min(RT\_OR\_LOC\_EOP_{r,k,h}^{i,t}, DAM\_QSOR_{r,k,h}^{i}/12) - RT\_QSOR_{r,k,h}^{i,t}) \times (ISPROR_{r,h}^{i,t} - DAM\_PROR_{r,h}^{i}) + OP(DAM\_PROR_{r,h}^{i}, Min(RT\_OR\_LOC\_EOP_{r,k,h}^{i,t}, DAM\_QSOR_{r,k,h}^{i} /12), BOR_{r,k,h}^{i,t})\}$$

Where:

'I'	is the set of all *intertie metering points* 'i'.
'T'	is the set of all *metering intervals* 't' in *settlement hour* 'h'.
'R'	is the set of each class r of *operating reserve.*
'EOP'	RT variables with 'EOP' are defined in Section 3.5.6 Table 3-35.
'$ISPROR_{r,h}^{i,t}$'	as defined in Section 3.5.6 Table 3-27.

Rule: BOR represents the RT *operating reserve offer* of the *market participant* adjusted for the DAM_BC. When the *offer* price in any of the 'N' by 2 matrix of the *price-quantity pairs* is less than the DAM_PROR, it will be replaced by the DAM_PROR.

Exports:

DAM_BC applies when the DAM_LMP is higher than the ISP for the applicable export. If the participant's real-time *bid* is at a lower price than the DAM_LMP, DAM_BC will be reduced by the reduced costs represented by the real-time *bid*.

$$BCE_{k,h}^{i} = Max\{0, \sum^{T} (Min(RT\_LOC\_EOP_{k,h}^{i,t}, DAM\_QSW_{k,h}^{i}/12) - SQEW_{k,h}^{i,t}) \times (DAM\_LMP_{h}^{i} - ISP_{h}^{i,t}) - OP(DAM\_LMP_{h}^{i}, Min(RT\_LOC\_EOP_{k,h}^{i,t}, DAM\_QSW_{k,h}^{i}/12), BL_{k,h}^{i,t})\}$$

Where:

'I'	is the set of all *intertie metering points* 'i'.
'T'	is the set of all *metering intervals* 't' in *settlement hour* 'h'.
'EOP'	RT variables with 'EOP' are defined in Section 3.5.6 Table 3-35.
'$ISP_h^{i,t}$'	as defined in Section 3.5.6 Table 3-27.

Rule: BL represents the RT *bid* of the *market participant* adjusted for the DAM_BC. When the *bid* price in any of the 'N' by 2 matrix of the *price-quantity pairs* is greater than the DAM_LMP, it will be replaced by the DAM_LMP.

3.7.7.2 Pseudo-Unit Settlement – DAM_BC

No PSU-specific version of the *settlement amount* is required.

3.7.8 DAM Balancing Credit Uplift (DAM_BCU)

The DAM balancing Credit uplift (DAM_BCU) is intended to recover the cost of the DAM_BC *settlement amounts* accrued in the *real-time market*.

The DAM_BCU is allocated on a pro-rata basis to all *real-time market* loads and exports on an hourly basis.

The formulation of the DAM_BCU is as follows:

$$DAM\_BCU_{k,h} = \sum\nolimits_{K} DAM\_BC_{k,h}\ x\ \left[\sum\nolimits^{M,T} \left(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t} + RQ_{k,h}^{m,i,t}\right) / \sum\nolimits_{K}^{M,T} \left(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}\right)\right]$$

Where:

'K'	is the set of all *market participants* 'k'.
'M'	is the set of all *delivery points* 'm' and *intertie metering points* 'i'.
'T'	is the set of all *metering intervals* 't' in *settlement hour* 'h'.
'$RQ_{k,h}^{m,i,t}$'	as defined in Section 3.5.6 Table 3-36.

3.7.9 Real-Time Generator Offer Guarantee (RT_GOG)

The RT_GOG payment will be calculated for *market participants* with eligible NQS *generation units* that are committed during the *pre-dispatch scheduling* process. The RT_GOG payment will replace the Real-Time Generation Cost Guarantee (RT-GCG) payment that is currently used in the *real-time market*. The *IESO* will provide the RT_GOG payment to compensate *market participants* for any loss they incur relative to costs implied by their *offers* for the period in which their resource is committed by the pre-dispatch calculation engine. RT_GOG will incorporate any required adjustment and mitigation test results into the calculation set out by the market power mitigation process, which is described in Section 3.13.

For NQS *generation facilities*, such revenues and costs will include:

- Revenues associated with the provision of *energy* and *operating reserve*; and
- Costs of production implied by financial offers: start-up offer, speed no-load offer, *energy offer*, and *operating reserve offer*.

RT_GOG payments to *market participants* are strictly compensatory in nature and therefore, *market participants* will not owe any RT_GOG payments to the *IESO*.

Table 3-61: Resolution of Real-Time GOG Calculation

Attribute	Resolution
Time resolution	Hourly
Geographic resolution	NQS *generation unit* within Ontario: • By *delivery point*
RT price accuracy (Energy and OR)	$/MWh to the nearest cent
RT *energy* quantities	MW schedule values converted to MWh values for the purposes of *settlement*, rounded to the nearest 0.1 MWh per hour or 0.001 MWh per 5-minute *metering interval*
DAM class 'r' operating quantities	MW schedule values converted to MWh values for the purposes of *settlement*
All *real-time market settlement* data	Includes: Revenue *metering data* at applicable *delivery points*

3.7.9.1 Eligibility

NQS Generation Unit Eligibility for RT_GOG

The following criteria will determine a *generation unit's* eligibility for RT_GOG:

- The *generation unit* is not a quick-start unit;
- The *generation unit* has a MLP greater than 0 MW;
- The *generation unit* has a MGBRT greater than one hour; and
- The *generation unit* has an *elapsed time to dispatch* greater than one hour.

An eligible NQS *generation unit* will be required to meet additional conditions in order to recover the implied cost of any start-up offer and the implied cost of any speed no-load offer as described in the following sub-sections:

Eligibility for Recovery of Implied Cost of Start-Up Offers

An NQS *generation unit* associated with a physical unit will be eligible to recover the implied costs of any start-up offer if:

- the *generation unit* synchronizes and comes online in real-time;
- the *generation unit* is committed for its entire MGBRT period and has completed its MGBRT;
- the *generation unit* is dispatched down by the *IESO* for reasons of *reliability*, such that the unit has to de-synchronize before the end of its MGBRT, the *generation unit* will remain eligible to recover its start-up offer*;*
- the *generation unit* does not follow directly after another commitment (pre-dispatch, day-ahead or *reliability* commitment) where the start-up offer is already considered;
- the *generation unit* receives a PD commitment in advance of a DAM commitment or a *reliability* commitment for a period shorter than its MGBRT plus its hot *minimum generation*

block down time (MGBDT), then the incremental start-up offer above the DAM start-up offer will be eligible for recovery;

- the *generation unit* receives a PD commitment in advance of a DAM commitment or a *reliability* commitment for a period longer than its MGBRT plus its hot MGBDT, then the start-up offer will be considered as part of the PD commitment instead of the DAM commitment; and
- the *IESO* will withhold or reduce the implied cost of start-up offers depending on when the *generation unit* actually reaches the MLP.

Table 3-62 describes the eligibility to recover the implied cost of start-up offers on the basis of when the resource achieves the MLP in order to meet its DAM financially binding schedule.

Table 3-62: Eligibility to Recover Implied Cost of Start-Up Offers

When did the resource reach MLP?	Start-up offer recovery
Within 30 minutes of the first hour of its PD commitment	Full
Within 30 to 90 minutes of the first hour of its PD commitment	Reduce by 1/12 for every 5-minute interval that it was more than 30 minutes late getting to MLP
90 minutes after the start of the first hour of its PD commitment	None

Eligibility for Recovery of Implied Cost of Speed No-Load Offers

The *IESO* will apply the following guidelines to determine the eligibility of an NQS *generation unit* not associated with a *pseudo-unit* to recover the implied cost of speed no-load offers:

- An NQS *generation unit* will be eligible to recover the implied cost of any speed no-load offer for each hour of its PD commitment period if the *generation unit* actually produces *energy* for the entire hour; and
- The *IESO* will reduce the implied cost of any speed no-load offer by 1/12th for each 5-minute interval where the *generation unit* did not produce *energy* for the full hour.

3.7.9.2 Interactions and Special Considerations

Extension Due to Late Reach of MLP

When a *generation unit* reaches MLP late, the *IESO* may extend the unit's operational constraint beyond its initial commitment to ensure the *generation unit* completes its MGBRT. If the unit is uneconomic in the *real-time market* for the extended period and the period is also not scheduled in the binding advisory schedule, then the RT_GOG evaluation will not cover the cost for the *generation unit* to maintain the operational constraint for the period. The cost includes the implied cost of speed no-load offer and *energy offer* up to MLP.

Interaction with DAM Financial Binding Ramp Up Schedule

If a *generation unit* receives a PD commitment in advance of a DAM commitment that overlaps with the DAM financial binding ramp up schedule, the revenue received from the DAM ramp up schedule, which has already been offset in the DAM_GOG calculation will be excluded in the evaluation of RT_GOG.

Interaction with RT_MWP

If a *generation unit* is dispatched out-of-merit in real-time for any interval of the RT_GOG eligible period, any revenue received through RT_MWP for the period will be included in the RT_GOG calculation.

End of Trading Day Commitment of NQS Generation Facilities

The PD calculation engine will commit a NQS *generation unit* toward the end of the *trading day* when economic, even if its MGBRT will require it to run beyond the end of the *trading day*. *Registered market participants* must submit escalating start-up offers at the end of the *trading day* to capture costs of the start-up offer, speed no-load offer and *energy offer* to MLP for each possible commitment hour in the next *trading day*.

A PD commitment for a unit that crosses over midnight will be assessed as a single event that is associated with the *dispatch day* when the binding start-up instruction is issued.

Interaction with Called Capacity Export

The *IESO* will not pay RT_GOG in situations where a *generation unit* has committed its capacity to an external *control area* and

- the external *control area operator* has called a capacity export prior to the capacity resource being scheduled for the commitment; or
- the external *control area operator* has called a capacity export after the capacity resource has been scheduled for the commitment, and the *IESO* is restricting other transactions on the interconnected system, while maintaining the *called capacity export* transaction.

Ramp-Down Cost

The RT_GOG calculation will not include intervals where the *generation unit is* dispatched below its MLP to ramp offline. The cost incurred during the ramp down period will be assessed separately from RT_GOG through the Real-Time Ramp Down Settlement Amount, as described in Section 3.7.16.

De-commitment of an NQS Generation Unit

A *generation unit* may be de-committed by the *IESO* for *reliability*, *security* or *adequacy* reasons after the unit receives a binding start-up instruction for a PD commitment. In the event that a *generation unit* is de-committed subsequent to receiving a binding start-up instruction, the *generation unit* will be compensated for any lost opportunity during the de-committed period through RT_MWP. Any *offered* cost incurred before the de-commitment including any start-up offer and speed no-load offer for the hours that the unit was online will be compensated through RT_GOG as per eligibility rules defined in the section above.

3.7.9.3 RT_GOG – Formulation

The RT_GOG formula will:

- include all the consecutive hours that the *generation unit* is committed by the PD calculation engine as well as the ramp up intervals that are directly associated with the PD commitment as one commitment event, provided that the *generation unit* has generated for the entire period; and

- assess the RT_GOG payment for any consecutive hours where the *generation unit* is committed for *dispatch* for *reliability* reasons independently from the economic PD commitment.

If the *IESO*, for reasons of *reliability*, *dispatches* the *generation unit* down, such that the *generation unit* has to de-synchronize before the end of its PD commitment period, the *generation unit* shall remain eligible for the RT_GOG for the hours that the *generation unit* is online.
The calculation of RT_GOG for an NQS *generation unit* associated with a physical unit is broken down into five components:

- Component 1: Any shortfall in payment over the PD commitment period for the *generation unit's* real-time *dispatch* schedule for *energy* will be based upon the real-time revenue received for that amount of *energy* over the PD commitment period in comparison with the cost represented in the real-time *offers* for *energy* and speed no-load offers;
- Component 2: Any shortfall in payment over the PD commitment period for the *generation unit's* real-time dispatch schedule for *operating reserves* will be based upon the real-time revenue received for that amount of *operating reserves* over the interval in comparison with the cost represented in the real-time *offers* for *operating reserve*;
- Component 3: The amount calculated by Component 1 up to MLP for the hours of MGBRT scheduled over midnight into the following *dispatch day*;
- Component 4: Any start-up offers to bring an offline *generation unit* through all the unit-specific start-up procedures, including synchronization and ramp up to MLP*;* and
- Component 5: Any real-time make-whole payment that was received as a result of being uneconomically scheduled in the *real-time market*.

The RT_GOG will be calculated for each PD commitment period for which a unit received a PD constraint from the PD calculation engine. An NQS *generation unit* can have multiple starts within a *dispatch day*, and each start will be assessed separately. RT_GOG will be calculated as:

$$RT\_GOG = Max[0, Component\ 1 + Component\ 2 - Component\ 3 + Component\ 4 - Component\ 5]$$

For each *generation unit,* the *IESO* will determine the type of schedule and which of the components described above to include in the RT_GOG calculations as follows:

- **Variant 1**: If the *generation unit* receives a PD commitment independently or in advance of a DAM commitment, and where the PD commitment does not cross over midnight to complete its MGBRT period, then the RT_GOG for the PD commitment includes components 1, 2, 4 and 5. Component 3 is not applicable because the *generation unit* was not injecting *energy* for the hours of MGBRT scheduled over midnight into the following *dispatch day*;
- **Variant 2**: If the *generation unit* receives a PD commitment immediately following a DAM commitment or *reliability* commitment under which the start-up offer is already considered, then the RT_GOG includes components 1, 2 and 5. Component 3 is not applicable because the PD commitment will not result in the *generation unit* injecting *energy* for the hours of MGBRT scheduled over midnight into the following *dispatch day*, because the *generation unit* has already completed MGBRT. Component 4 is not applicable because the start-up offer was included in the calculation for the previous *dispatch day*; and
- **Variant 3:** If the *generation unit* receives a PD commitment independently of or in advance of a DAM financially binding schedule, and where the PD commitment crosses over

midnight to complete its MGBRT period, then the RT_GOG includes components 1 through 5.

The components will be calculated using the operating profit function described in Section 3.7.1 – DAM Make-Whole Payment (DAM_MWP) and in *IESO market rules* Section 9.3.8A.2.

Component 1 – applicable to Variants 1, 2 and 3

Component 1 includes any shortfall in payment for the *generation unit's* real-time economic operating point for *energy* based upon the real-time revenue received over the pre-dispatch commitment for that amount of *energy*.

$$RT\_GOG\_COMP1_{k}^{m} = \sum^{T}\Bigg[(-1) \times Max\left(OP\left(RT\_LMP_{h}^{m,t}, RT\_QSI_{k,h}^{m,t}, BE_{k,h}^{m,t}\right), OP\left(RT\_LMP_{h}^{m,t}, AQEI_{k,h}^{m,t}, BE_{k,h}^{m,t}\right)\right) + \frac{PD\_BE\_SNL_{k,h}^{m}}{12}\Bigg] - \sum^{T0}\left[RT\_LMP_{h}^{m,t} \times AQEI_{k,h}^{m,t}\right] + \sum^{RH}\left[DAM\_LMP_{h}^{m}\ x\ DAM\_QSI_{k,h}^{m}/12\right]$$

Where

‘T’ is the set of all *settlement intervals* ‘t’ beginning from the first interval that the *generation unit* is at the *minimum loading point* with a unit commitment schedule until the last interval that the *generation unit* is at the *minimum loading point* with a unit commitment schedule.

‘T0’ is the set of all *settlement* intervals ‘t’ between the time when the *generation unit* synchronizes and the time the *generation unit* reaches its *minimum loading point*, regardless of whether the *generation unit*'s PD commitment schedule has begun by the time it reaches its *minimum loading point.*

- For Variant 1 and 3, ‘T0’ refers to the start immediately preceding the unit commitment schedule in question.
- For Variant 2, since the unit commitment schedule follows a separate commitment period rather than a new start, the variable ‘T0’ represents an empty set.

‘RH’ is the set of contiguous hours with DAM financial binding schedules for the ramp-up period.

Component 2 – applicable to Variants 1, 2 and 3

Component 2 includes any shortfall in payment for the *generation unit's* real-time economic operating point for *operating reserves* based upon the real-time revenue received over the interval for that amount of *operating reserves.* Component 2 applies to all three *operating reserve* products (30-minute *operating reserve*, 10-minute non-spinning *operating reserve*, and 10-minute spinning *operating reserve*).

$$RT\_GOG\_COMP2_{k}^{m} = (-1) \times \sum_{R}^{T1} OP\left(RT\_PROR_{r,h}^{m,t}, RT\_\mathrm{QSOR}_{r,k,h}^{m,t}, BOR_{r,k,h}^{m,t}\right)$$

Where:

'T1'	is the set of all *settlement* interval 't' beginning from the first interval that the *generation unit* is at *minimum loading point* with a unit commitment schedule until the last interval that the *generation unit* is at *minimum loading point* with a unit commitment schedule.
'R'	is the set of each class r of *operating reserve.*

Component 3 – applicable to Variant 3

Component 3 is the amount calculated under Component 1 up to the *minimum loading point* for each hour that the NQS *generation unit* is scheduled by the PD calculation engine over midnight to complete its MGBRT.

$$RT\_GOG\_COMP3_k^m = \sum^{T2}[(-1)\ x\ \left(OP(RT\_LMP_{k,h}^{m,t}, MLP_k^m, BE_{k,h}^{m,t})\right) + \frac{PD\_BE\_SNL_{k,h}^m}{12}]$$

Where:

'T2'	is the set of all *settlement* intervals 't' where the *generation unit* is scheduled over midnight to complete its MGBRT in the following *trading day.*
'MLP_k^m'	is the *minimum loading point* submitted by *market participant* 'k' for *delivery point* 'm'. In this instance, MLP refers to the current *trading day.*

Component 4 – applicable to Variants 1 and 3

Component 4 is the start-up offer, subject to mitigation, to bring an offline *generation unit* through all the unit specific start-up procedures, including synchronization and ramp up to *minimum loading point*.

$$GOG\_COMP4_k^m = RT\_GOG\_SU_{k,h}^m$$

For **Variants 1 and 3**, when the *generation unit* is committed as a stand-alone PD commitment or when the *generation unit* is committed in advance of a pre-existing DAM commitment for longer than its MGBRT plus hot MGBDT.

$$RT\_GOG\_SU_{k,h}^m = PD\_BE\_SU_{k,h}^m$$

For **Variants 1 and 3**, when the *generation unit* is committed in advance of a pre-existing DAM commitment for shorter than its MGBRT plus hot MGBDT:

$$RT\_GOG\_SU_{k,h}^m = Max\left(0, PD\_BE\_SU_{k,h}^m - DAM\_BE\_SU_{k,h}^m\right)$$

Where:

'$RT\_GOG\_SU_{k,h}^m$'	as defined in Section 3.5.6 Table 3-33.

For **Variant 2**, when the PD commitment immediately follows another commitment:

$$RT\_GOG\_SU_{k,h}^m = 0$$

The $RT\_GOG\_SU_{k,h}^m$ will be adjusted depending on when the *generation unit* achieved MLP:

a. If MLP was achieved within the first 6 intervals of the first hour of its MGBRT:

$$RT\_GOG\_COMP4_k^m = RT\_GOG\_SU_{k,h}^m$$

b. If MLP was achieved within intervals 7 and 18 of the first two hours of the its MGBRT:

$$RT\_GOG\_COMP4_k^m = RT\_GOG\_SU_{k,h}^m - (RT\_GOG\_SU_{k,h}^m \times N\_INT\ /12)$$

Where:

'N_INT'	is the number of intervals between 7 and 18 that the resource achieved MLP.
'$RT\_GOG\_SU^{m}_{k,h}$'	as defined in Section 3.5.6 Table 3-33.

c. If MLP was achieved after interval 18 of the first two hours of the its MGBRT:

$$RT\_GOG\_COMP4^{m}_{k} = 0$$

Component 5 - applicable to all Variants

Component 5 is the sum of all real-time make-whole payments received by the NQS *generation facility* over the PD commitment period.

$$RT\_GOG\_COMP5^{m}_{k} = \sum^{T3} RT\_MWP^{m}_{k,h}$$

Where:

'T3'	is the set of all *dispatch intervals* 't' beginning from the first interval that the *generation unit* is at *minimum loading point* with a unit commitment schedule until the last interval that the *generation unit* is at *minimum loading point* with a unit commitment schedule.

3.7.9.4 Pseudo-Unit Settlement – RT_GOG Formulation

The RT_GOG for a *pseudo-unit* will be settled on the physical *generation unit* basis. An NQS *generation unit* associated with a *pseudo-unit* will be eligible for a RT_GOG provided it meets the specific eligibility requirements. These eligibility requirements are similar to those for an NQS *generation unit* associated with a physical unit. The interactions and considerations for the physical unit will apply to these units as well.

3.7.9.5 Eligibility

Eligibility for Recovery of Implied Cost of Start-Up Offers

An NQS *generation unit* combustion turbine (CT) associated with a *pseudo-unit* will be eligible to recover its full share of the PSU's implied costs of any start-up offer if:

- the CT synchronizes and comes online in real-time;
- the PSU associated with the CT is committed for its entire MGBRT period and has completed its entire MGBRT period;
- the PD commitment of the associated PSU does not follow directly after another commitment where the start-up offer is already considered;
- the PSU associated with the CT receives a PD commitment in advance of a DAM or *reliability* commitment for a period shorter than its MGBRT plus its hot MGBDT, then the incremental start-up offer above the DAM or *reliability* start-up offer will be eligible for recovery in RT_GOG; and
- the PSU associated with the CT receives a PD commitment in advance of a DAM commitment for a period longer than its MGBRT plus its hot MGBDT, then the start-up offer will be considered as part of the PD commitment instead of the DAM or *reliability* commitment.

An NQS *generation unit* steam turbine (ST) associated with a *pseudo-unit* will be eligible to recover its share of the implied costs of any start-up offer for each associated PSU where the associated CT is not operating in single-cycle mode and meets the above eligibility requirements.

The *IESO* will withhold or reduce the implied cost of a PSU's start-up offers depending on when the associated CT actually reaches its MLP.

Table 3-63 describes the portion of each PSU's implied cost of start-up offers that are eligible for recovery based on the time when the associated CT achieves its MLP in order to meet its PD commitment.

Table 3-63: Eligibility to Recover Implied Cost of PSU Start-Up Offers

When did the associated CT reach MLP?	Start-up offer recovery
Within 30 minutes of the first hour of its PD commitment	Full
Within 30 to 90 minutes of the first hour of its PD commitment	Reduce by 1/12 for every 5-minute interval that it was more than 30 minutes late getting to MLP
90 minutes after the start of the first hour of its PD commitment	None

Eligibility for Recovery of Implied Cost of Speed No-Load Offers

An NQS *generation unit* combustion turbine (CT) associated with a *pseudo-unit* will be eligible to recover its share of the associated PSU's cost of speed no-load offers for each hour of its PD commitment period when the CT actually produces *energy* for the entire hour. The *IESO* will reduce the implied cost of any speed no-load offer for a given hour by 1/12th for each 5-minute interval in that hour where the CT did not produce *energy*.

An ST associated with one or more PSUs will recover its share of each associated PSU's speed no-load offer in every hour of that PSU's commitment period when the associated CT is not operating in a single-cycle mode and actually produces *energy* for the entire hour. The *IESO* will reduce the implied cost of any speed no-load offer for a given hour by 1/12th for each 5-minute interval in that hour where the CT either (1) operated in a single-cycle mode or (2) did not produce *energy*. The eligibility criteria will apply to any and all PSUs associated with the given ST, such that the ST can potentially recover speed no-load offers from multiple overlapping PSU commitments throughout its calculation period.

3.7.9.6 Interactions and Special Considerations

Pseudo-Unit Operating in Single Cycle Mode

To achieve a consistent *settlement* treatment with a PSU operating in a combined-cycle mode, RT_GOG requires a different calculation when a PSU receives a PD commitment but, due to a failure or *outage* at the associated ST, operates in a single-cycle mode in real time for any period of its PD commitment.

Calculation of RT_GOG for the ST will be treated the same as for a failure or *outage* at any other NQS *generation unit*.

An ST failure or *outage* resulting in a single-cycle operation will not affect the associated CT's eligibility for recovery of implied costs of start-up offers or speed no-load offers. However, since a CT that switches to the single cycle mode after being committed as part of a PSU will be allowed to change its *offers* for *energy* above MLP to reflect its cost of operation in a single-cycle mode, the real-time *offers* for the CT units after the switch will not be considered in the RT_GOG. Instead, RT_GOG will be calculated using the *offer* before the switch has occurred.

3.7.9.7 Formulation

Derived Variables

The calculation of RT_GOG for *pseudo-units* will require *offers* and schedules associated with the *pseudo-unit* to be translated. For individual physical CT and ST units, the translated *offers* are known as the Derived Interval Price Curve or DIPC. The translated schedules are known as the Derived Interval Guaranteed Quantity or DIGQ.

Due to the operation in a single-cycle mode, the following variables will be derived differently than when the PSU is operating in combined cycle mode:

- CT–RT_GOG_DIPC for *energy* and OR_RT_GOG_DIPC for each class of *operating reserve*; and ST–RT_GOG_DIPC and RT_GOG_DIGQ for *energy,* as well as OR_RT_GOG_DIPC and OR_RT_GOG_DIGQ for each class of *operating reserve*.

When operating in a combined-cycle mode, these variables will be derived from the real-time PSU *offer* curves and the real-time schedule and injection for each *energy* and *operating reserve* product. These formulations will allow comparisons of all as-offered costs against actual revenues in the *energy market* for the PU.

For any intervals when a CT associated with a PSU operated in single cycle mode, the RT_GOG_DIPC and OR_RT_GOG_DIPC will be derived from the pre-dispatch PSU *offer* curves that are submitted to the PD run that issued the commitment. In this case, the real-time PSU *offer* curves will not be used. This distinction is necessitated by the exemption that allows these resources to increase their *offers* for *energy* above MLP having already received a PD commitment.

CT Associated with a Pseudo-Unit

For a CT associated with a PSU, the RT_GOG formula will:

- include all consecutive hours that the *generation unit* is committed by the PD engine and ramp up intervals associated with the PD commitment as one commitment event, provided that the resource has generated *energy* for the entire period; and
- assess the RT_GOG payment for any consecutive hours where the *generation unit* is committed for *reliability* reasons independently from a PD engine commitment.

The calculation of RT_GOG for an NQS *generation unit* combustion turbine (CT) associated with a *pseudo-unit* is broken down into the same five (5) components as the RT_GOG for non-PSU NQS *generation units*, as further described in the sections below.

RT_GOG for a CT associated with a PSU will be calculated as:

$$RT\_GOG = Max[0, Component\ 1 + Component\ 2 - Component\ 3 + Component\ 4 - \text{Component 5}]$$

For each CT associated with a PSU, the *IESO* will determine the type of schedule and which of the components described later to include in the RT_GOG calculation based on one of three variants. The three variants are defined as follows:

- **Variant 1**: If the PSU associated with the CT receives a PD commitment independently of or in advance of a DAM commitment, and where the PD commitment does not cross over midnight to complete its MGBRT period, then the RT_GOG for the commitment includes components 1, 2, 4 and 5.

- Component 3 is not applicable because the PD commitment will not result in the PSU injecting *energy* for the hours of MGBRT scheduled over midnight into the following *dispatch day*.

- **Variant 2**: If the PSU associated with the CT receives a PD commitment immediately following a DAM commitment or *reliability* commitment under which the start-up offer is already considered, and where the PD commitment does not cross over midnight to complete its MGBRT period, then the RT_GOG includes components 1, 2, and 5.
  - Component 3 is not applicable because the PD commitment will not result in the *generation unit* injecting *energy* for the hours of MGBRT scheduled over midnight into the following *dispatch day*, because the *generation unit* has already completed MGBRT. Component 4 is not applicable because the start-up offer was included in the calculation for the previous *dispatch day*.
- **Variant 3**: If the PSU associated with the CT receives a PD commitment independently of or in advance of a DAM financially binding schedule, and where the PD commitment crosses over midnight to complete its MGBRT period, then the RT_GOG includes components 1 through 5.

Components 1 – applicable to Variants 1, 2 and 3

Component 1 is the shortfall in payment over the commitment period for the CT's share of its associated PSU's real-time *dispatch* for *energy* based upon the real-time revenue received for that amount of *energy* over the PD commitment period in comparison with the cost represented in the real-time *offers* for *energy* and speed no-load.

$$
\begin{aligned}
&RT\_GOG\_COMP1_k^c \\
&= \sum^{T}\Bigg[(-1) \\
&\times \text{Max}\Big(OP\big(RT\_LMP\,{}_h^{c,t}, RT\_QSI_{k,h}^{c,t}, RT\_GOG\_DIPC_{k,h}^{c,t}\big), OP\big(RT\_LMP\,{}_h^{c,t}, AQEI_{k,h}^{c,t}, RT\_GOG\_DIPC_{k,h}^{c,t}\big)\Big) \\
&+ \frac{PD\_BE\_SNL_{k,h}^{p}}{12} \times \big(1 - ST\_Portion_{k,d1}^{p}\big)\Bigg] - \sum^{T0}\big(RT\_LMP_h^{c,t} \times AQEI_{k,h}^{c,t}\big) \\
&+ \sum^{RH}\big[DAM\_LMP_h^{c} \times DAM\_QSI_{k,h}^{c}/12\big]
\end{aligned}
$$

Where:

'T' is the set of all *settlement* intervals 't' beginning from the first interval that the CT is at its *minimum loading point* with a unit commitment schedule until the last interval the CT is at its *minimum loading point* with a unit commitment schedule.

'T0' is the set of all *settlement* intervals 't' between the time when the CT synchronizes and the time the CT reaches its *minimum loading point*, regardless of whether the CT's PD advisory schedule has begun by the time it reaches its *minimum loading point.*

- For Variants 1 and 3: 'T0' refers to the start immediately preceding the PD commitment period in question.
- For Variant 2: since the PD commitment period immediately follows a separate DAM financially binding schedule or *reliability* commitment and does not require a new start, the variable 'T0' represents an empty set.

‘RH’	is the set of contiguous hours with DAM financially binding schedules for the ramp-up period. This only applies to instances where the PD commitment period is an advance of a separate DAM commitment, where the PSU has an operational constraint at MLP by the PD engine when it would otherwise be ramping up to meet a DAM financially binding schedule.
‘p’	is the *pseudo-unit* associated with CT *delivery point* ‘c’.
‘DIPC’	RT variables with ‘DIPC’ are defined in Section 3.5.6 Table 3-35.
‘$ST\_Portion^{p}_{k,d1}$’	as defined in Section 3.5.9 Table 3-37.

Component 2 – applicable to Variants 1, 2 and 3

Component 2 is the shortfall in payment over the PD commitment period for the CT’s share of the PSU’s real-time schedule for *operating reserves* based upon the real-time revenue that would be received for the amount of *operating reserves*, in comparison with the cost represented in the real-time *offers* for *operating reserve.*

$$RT\_GOG\_COMP2^{c}_{k} = \sum\nolimits_{R}^{T1} \left[(-1) \times OP\left(RT\_PROR^{c,t}_{r,h}, RT\_QSOR^{c,t}_{r,k,h}, OR\_RT\_GOG\_DIPC^{c,t}_{r,k,h}\right)\right]$$

Where:

‘T1’	is the set of all *settlement* intervals ‘t’ beginning from the first interval in GOG calculation period ‘x’ that the corresponding PSU ‘p’ is at its *minimum loading point* with a unit commitment schedule until the last interval that the corresponding PSU ‘p’ is at its *minimum loading point* with a unit commitment schedule
‘R’	is the set of each class r of *operating reserve*.
‘DIPC’	RT variables with ‘DIPC’ are defined in Section 3.5.6 Table 3-35.

Component 3 – applicable to Variant 3

Component 3 is the amount calculated by Component 1 up to the CT’s share of the PSU’s MLP for each hour that the PSU is scheduled by the PD engine over midnight into the following *dispatch day* to complete its MGBRT.

$$RT\_GOG\_COMP3^{c}_{k} = \sum\nolimits^{T2} \left[(-1) \times \left(OP\left(RT\_LMP^{c,t}_{,h}, MLP^{c}_{k}, RT\_GOG\_DIPC^{c,t}_{k,h}\right)\right) + \frac{PD\_BE\_SNL^{p}_{k,h}}{12} \times \left(1 - ST\_Portion^{p}_{k,d1}\right)\right]$$

Where:

‘T2’	is the set of all *settlement* intervals ‘t’ where the PSU associated with CT ‘c’ is scheduled over midnight to complete its MGBRT period in the following *trading day.*
‘MLP^{c}_{k}’	is the *minimum loading point* submitted by *market participant* ‘k’ for CT *delivery point* ‘c’. In this instance, MLP refers to the current *trading day*.
‘DIPC’	RT variables with ‘DIPC’ are defined in Section 3.5.6 Table 3-35.
‘$ST\_Portion^{p}_{k,d1}$’	as defined in Section 3.5.9 Table 3-37.

Component 4 – applicable to Variants 1 and 3

Component 4 is the CT's share of the start-up offers to bring an offline *pseudo-unit* through all the unit specific start-up procedures, including synchronization and ramp up to MLP.

For a PD commitment period where the associated PSU is committed as a stand-alone PD commitment or when the associated PSU is committed in advance of a pre-existing DAM commitment for longer than its MGBRT plus hot MGBDT:

a. If the CT achieved its MLP within the first 6 *metering intervals* of its PD advisory schedule:

$$RT\_GOG\_COMP4_k^c = PD\_BE\_SU_{k,h}^p \times \left(1 - ST\_Portion_{k,d1}^p\right)$$

b. If the CT achieved its MLP between the 7th and 18th *metering interval* of its PD advisory schedule:

$$RT\_GOG\_COMP4_k^c = PD\_BE\_SU_{k,h}^p \times \left(1 - ST\_Portion_{k,d1}^p\right) \times \left(1 - \frac{N\_INT_k^c}{12}\right)$$

Where:

'$N\_INT_k^c$'	is the number of *metering intervals* that elapsed between the beginning of the associated PSU's PD advisory schedule and the time the CT achieved its MLP, minus 6 *metering intervals.*
'$ST\_Portion_{k,d1}^p$'	as defined in Section 3.5.9 Table 3-37.

c. If the CT achieved its MLP after the 18th *metering interval* of its PD advisory schedule:

$$RT\_GOG\_COMP4_k^c = 0$$

For a PD commitment period where the associated PSU is committed in advance of a pre-existing DAM commitment for shorter than its MGBRT plus hot MGBDT:

a. If the CT achieved its MLP within the first six *metering intervals* of its PD advisory schedule:

$$RT\_GOG\_COMP4_k^c = Max\left(0, PD\_BE\_SU_{k,h}^p - DAM\_BE\_SU_{k,h}^p\right) \times \left(1 - ST\_Portion_{k,d1}^p\right)$$

b. If the CT achieved its MLP between the 7th and 18th *metering interval* of its PD advisory schedule:

$$RT\_GOG\_COMP4_k^c = Max\left(0, PD\_BE\_SU_{k,h}^p - DAM\_BE\_SU_{k,h}^p\right) \times \left(1 - ST\_Portion_{k,d1}^p\right) \times \left(1 - \frac{N\_INT_k^c}{12}\right)$$

Where:

'$N\_INT_k^c$'	is the number of *metering intervals* that elapsed between the beginning of the associated PSU's PD advisory schedule and the time the CT achieved its MLP, minus 6 *metering intervals.*
'$ST\_Portion_{k,d1}^p$'	as defined in Section 3.5.9 Table 3-37.

c. If the CT achieved its MLP after the 18th *metering interval* of its PD advisory schedule:

$$RT\_GOG\_COMP4_k^c = 0$$

Component 5 - applicable to all Variants

Component 5 is the sum of all real-time make-whole payments received by the CT over the PD commitment period as a result of being uneconomically scheduled in the *real-time market*.

$$RT\_GOG\_COMP5_k^c = \sum^{T3} RT\_MWP_{k,h}^c$$

Where:

'T3'	is the set of all *settlement* intervals 't' beginning from the first interval that the CT is at its *minimum loading point* with a unit commitment schedule until the last interval the CT is at its *minimum loading point* with a unit commitment schedule.

ST Associated with a Pseudo-Unit

For an ST associated with a PSU, the RT_GOG formula will be calculated across a period referred to as the RT_GOG calculation period. The RT_GOG calculation period:

- is a contiguous block of time where at least one of the ST's associated PSUs was operationally constrained at its MLP by the PD engine, and then injected in real-time;
- includes extensions of the operational constraint made by the PD calculation engine; and
- includes any ramp up intervals that are directly associated with an included PD commitment.

The start of the GOG calculation period will coincide with the synchronization of the CT associated with whichever PSU first received binding start-up instructions from the PD calculation engine, and it will persist until the first interval in which none of the associated CTs are injecting at MLP with an operational constraint from the PD calculation engine.

The calculation of RT_GOG for an NQS *generation unit* ST associated with a *pseudo-unit* is broken down into the same five (5) components as the RT_GOG for non-PSU NQS *generation units*, as further described in the sections below.

Unlike that of its CT counterparts, an ST's RT_GOG calculation does not need to be assigned a variant classification. The RT_GOG calculation for an ST will apply under all possible scenarios. For any ST associated with one or more PSUs, the RT_GOG for a given RT_GOG calculation period for a *market participant* 'k' at ST *delivery point* 's' will be calculated as:

$$RT\_GOG = Max[0, Component\ 1 + Component\ 2 - Component\ 3 + Component\ 4 - \text{Component 5}]$$

Component 1

Component 1 is the shortfall in payment on the ST's share of the real-time economic operating point for *energy* for each associated PSU PD commitment period that coincides with the ST's RT_GOG calculation period. Component 1 will be based upon the real-time revenue received for that amount of *energy* over the PD commitment period in comparison with the cost represented in the real-time *offers* for *energy* and speed no-load.

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

Where:

'T'	is the set of all *settlement* intervals 't' in the ST's RT_GOG calculation period where at least one of the associated PSUs is at its *minimum loading point* with a unit commitment schedule.
'N'	is the set of all PSUs associated with steam turbine 's' that are eligible for RT_GOG in *metering interval* 't' of *settlement hour* 'h'. In order to be eligible, the PSU must have a PD commitment above MLP, an associated CT that is injecting at or above its MLP, and no *reliability* commitment or DAM financially binding schedule above MLP.
'D'	is the set of all PSUs associated with steam turbine 's' that have: (1) a PD commitment above MLP in *metering interval* 't'; (2) an associated CT that is injecting at or above MLP in *metering interval* 't'; and (3) a DAM financially binding schedule below MLP in *metering interval* 't'.
'T0'	is the set of all *settlement* intervals 't' in the RT_GOG calculation period when: (1) the ST is below its MLP for a 1x1 configuration; and (2) none of the associated PSUs have DAM financially binding schedules. Note that such an interval will only occur at the beginning of the ST RT_GOG calculation period, and it will only occur if (1) the ST was not already synchronized prior to the RT_GOG calculation period; and (2) the only PSU(s) ramping up in that interval is (are) doing so to meet a PD commitment rather than a DAM financially binding schedule or *reliability* commitment.
'DIPC'	RT variables with 'DIPC' are defined in Section 3.5.6 Table 3-35.
'DIGQ	RT variables with 'DIGQ' are defined in Section 3.5.6 Table 3-35.
'$\mathrm{ST\_Portion}_{\mathrm{k,d1}}^{\mathrm{p}}$'	as defined in Section 3.5.9 Table 3-37.

Component 2

Component 2 is the shortfall in payment on the ST's share of the real-time schedule for *operating reserves* for each associated PSU PD commitment period that coincides with the ST's RT_GOG calculation period. Component 2 will be based upon the real-time revenue that would be received over each PSU's PD commitment period for supplying *operating reserves*, in comparison with the cost represented in the real-time *offers* for *operating reserves.*

$$RT\_GOG\_COMP2_k^s = \sum_{R}^{T2}\left[(-1) \times OP\left(RT\_PROR_{r,h}^{s,t}, OR\_RT\_GOG\_DIGQ_{r,k,h}^{s,t}, OR\_RT\_GOG\_DIPC_{r,k,h}^{s,t}\right)\right]$$

Where:

'T2'	is the set of all *settlement* intervals 't' in the ST's RT_GOG calculation period where at least one of the associated PSUs is at its *minimum loading point* with a unit commitment schedule.
'R'	is the set of each class r of *operating reserve*.
'DIPC'	RT variables with 'DIPC' are defined in Section 3.5.6 Table 3-35.
'DIGQ	RT variables with 'DIGQ' are defined in Section 3.5.6 Table 3-35.

Component 3

Component 3 is the amount calculated by Component 1 up to the ST's share of each associated PSU's MLP for each hour that the PSU is scheduled by the PD calculation engine over midnight to complete its MGBRT as a part of the PD commitment period that coincides with the ST's RT_GOG calculation period.

$$RT\_GOG\_COMP3_k^s = \sum^{U}\sum^{T_p}\left[(-1)\times\left(OP\left(RT\_LMP_h^{s,t},\left(MLP_k^p\times ST\_Portion_{k,d1}^p\right),BE_{k,h}^{p,t}\right)\right) + \frac{PD\_BE\_SNL_{k,h}^p}{12}\times\left(1-ST\_Portion_{k,d1}^p\right)\right]$$

Where:

'U'	is the set of all PSUs 'p' associated with ST 's' that (1) were scheduled over midnight to complete their MGBRT period in the following *trading day*, as a part of a PD commitment that is included in the ST's RT_GOG calculation period.
'T_p'	is the set of all *metering intervals* 't' where (1) the PSU 'p' was scheduled over midnight to complete its MGBRT period in the following *trading day*; and (2) the CT associated with PSU 'p' actually injected *energy* at or above its MLP.
'MLP_k^p'	is the *minimum loading point* for *pseudo-unit* 'p' for *market participant* 'k'.
'$ST\_Portion_{k,d1}^p$'	as defined in Section 3.5.9 Table 3-37.

Component 4

Component 4 is the ST's share of the start-up offers for any of its associated PSU PD commitments where the associated CT's PD commitment period is eligible for start-up recovery.

$$RT\_GOG\_COMP4_k^s = \sum_{c=1}^{C}\sum^{X_c}\left[RT\_GOG\_COMP4_{k,x}^c\times\frac{ST\_Portion_{k,d1}^p}{\left(1-ST\_Portion_{k,d1}^p\right)}\right]$$

Where:

'C'	is the set of all CT *delivery points* 'c' associated with ST *delivery point* 's'.
'X_c'	is the set of all PD commitment periods 'x', with a classification of Variant 1 or Variant 3, that were incurred by CT 'c' during the ST's RT_GOG calculation period.
$RT\_GOG\_COMP4_{k,x}^c$	is the RT_GOG Component 4 quantity for the PD commitment period 'x' of CT 'c'.
'$ST\_Portion_{k,d1}^p$'	as defined in Section 3.5.9 Table 3-37.

Component 5 – applicable to all Variants

Component 5 is any real-time make-whole payment that was received by ST as a result of being uneconomically scheduled in the *real-time market*.

$$RT\_GOG\_COMP5_k^s = \sum^{T3} RT\_MWP_{k,h}^s$$

Where:

'T3'	is the set of all *settlement* intervals 't' in the ST's RT_GOG calculation period where at least one of the associated PSUs is at its *minimum loading point* with a unit commitment schedule.

3.7.10 RT_GOG Uplift (RT_GOGU)

The Real-Time Generator Offer Guarantee uplift (RT_GOGU) is intended to recover the cost of the RT_GOG *settlement amounts* accrued for all NQS *generation facilities* committed in the *pre-dispatch scheduling* process.

The RT_GOG Uplift is allocated on a pro-rata basis to all *real-time market* loads and exports on a daily basis.

The formulation of the GOG Uplift is as follows:

$$RT\_GOGU_k = \sum_{K,H}^{M,T} RT\_GOG_{k,h}^m \times \left[\sum_H^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}) \,/\, \sum_{K,H}^{M,T} \left(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}\right)\right]$$

Where:

'M'	is the set of all *delivery points* 'm' and *intertie metering points* 'i'.
'T'	is the set of all *metering intervals* 't' in *settlement hour* 'h'.
'K'	is the set of all *market participants* 'k'.
'H'	is the set of all *settlement hours* 'h' in the *trading day*.

3.7.11 Generator Failure Charge (GFC)

The calculation of the Generator Failure Charge (GFC) will occur when a *generation unit* fails to deliver *energy* as committed by the PD calculation engine. The failure charge is intended to reduce the risk of system *reliability* events due to failed commitments and to improve efficiency.

Table 3-64: Resolution of Generator Failure Charge Calculation

Attribute	Resolution
Time resolution	Hourly
Geographic resolution	Applicable *generation unit* within Ontario: • By *delivery point*
Price accuracy (PD and RT)	$/MWh to the nearest cent
RT and PD energy quantities	MW schedule values converted to MWh values for the purposes of *settlement*, rounded to the nearest 0.1 MWh per hour or 0.001 MWh per 5-minute *metering interval*
All *real-time market settlement* data	Includes: Real-time measurement data at applicable *delivery points*

3.7.11.1 Triggers

If the *generation unit* has a real-time *dispatch* schedule below MLP at any time during an hour where there is an operational constraint resulting from the PD commitment, the failure charge calculation will be triggered. Scenarios include:

- Failing to ramp to MLP on schedule;
- Failing to operate until the end of its commitment period including any extensions to the unit commitment occurring in PD resulting in an operational constraint; or
- Failing to operate at all.

3.7.11.2 Period Subject to the Generator Failure Charge

A *generation unit* must violate an operational constraint in order for a failure charge to be triggered. However, the assessment of the failure charge might include hours that did not have any operational constraint when the unit's PD advisory schedule at Binding Start-Up Instruction (BSUI) extends for additional hours beyond the end of the unit's operational commitment. In that case, the hours between the end of the operational commitment and the end of the PD advisory schedule at BSUI will be included in the calculation of both components of the GFC.

Table 3-65: Types of Failure and Periods Subject to Failure Charge Assessment

Type of Failure	Failure Intervals
Failing to operate at all	All hours where a *generation unit* has a schedule at MLP or above MLP in the PD advisory schedule issued at the time of binding start-up instruction.
Failing to reach MLP on time	From the first interval where a *generation unit* has an operational constraint for PD commitment, till the last interval where the resource has a real-time schedule below MLP.
Failing to complete its MGBRT commitment	From the first interval where the *generation unit* is scheduled below MLP in real-time to come offline due to failure, till the last interval where the *generating unit* is scheduled above MLP in the PD advisory schedule issued at the time binding start-up instruction
Failure to complete its extension commitment, where the extension period is still within the PD binding start-up advisory schedule period.	From the first interval where the *generating unit* is scheduled below its MLP till the earlier of: • The end of PD advisory schedule issued at the time binding start-up instruction; or • The end of the PD advisory schedule at the time of extension.
Failure to complete its extension commitment, where the extension period is outside the PD binding start-up advisory schedule period.	From the first interval where the *generating unit* is scheduled below its MLP till the end of its PD operational constraint for PD commitment.

3.7.11.3 Special Considerations and Interactions

Exemption

The *IESO* recognizes that a failure to meet a PD commitment may occur for reasons outside the control of the applicable *generation unit*. A failure charge will not be applied if the *generation unit* is incapable of injecting to the grid due to an unplanned *outage* on the electrical system.

If the *IESO* dispatches a *generation unit* down for *reliability* reasons during a PD commitment, this will not be considered a failure. If the *IESO* commits a *generation unit* for *reliability* reasons, and the *generation unit* fails to meet the *reliability* commitment, this will also not be considered a failure.

Interactions with DAM Schedule

If a resource receives a DAM schedule for any period that is within the PD commitment Failure Intervals defined in Table 3-65, the GFC will not consider these DAM scheduled quantities as *energy* not delivered for the PD commitment.

3.7.11.4 Components of GFC

The GFC has two components:

- The Market Price Component (GFC_MPC): This component represents the impact to the *market price* increase due to the *generation unit's* failure; and
- The Guarantee Cost Component (GFC_GCC): This component represents an approximation of the guarantee cost of the replacement *generation unit*, if applicable.

The following sub-sections describe these components in further detail including their formulation and the uplift calculations.

3.7.11.5 Generator Failure Charge – Market Price Component (GFC_MPC)

The GFC_MPC formula will be assessed on an hourly basis, and it will calculate a charge for every interval within that hour that is classified as a Failure Interval, as defined by Table 3-65.

The *market price* component represents the impact to the *market price* increase due to the *generation unit's* failure. The market price component is equal to A × B, where:

- 'A' is the $/MWh amount, which is the difference between the *generation unit's* pre-dispatch (PD) LMP at the time of commitment and the applicable LMP after the failure for each hour of the commitment period where the *generation unit* has failed to be scheduled at the MLP. The applicable LMP to be used for the failure charge is the real-time (RT) LMP, if notice is provided after the binding start-up instruction, but less than four hours before the start of the MLP and the MGBRT commitment. If notice of the failure is provided to the *IESO* at least four hours before the start of these commitments, the price used will be the lower of the hour ahead of the PD_LMP and the RT_LMP.
- 'B' is the quantity of *energy* not delivered. The quantity not delivered will be the difference in MWh, during the hours of the failure, between the actual quantity of *energy* injected and the binding PD schedule.

A failure charge will not result in a payment to a *generation unit*, even if the applicable LMP is lower than the LMP at the time of commitment.

GFC – Market Price Component Formula:

If the *market participant* provides less than 4 hours of notice ahead of a given failure or if the notice of failure is absent, then the Generator Failure Charge – Market Price Component Formula is calculated as:

$$GFC\_MPC_{k,h}^{m} = \sum^{T} Min\left[0, -1 \times \left(RT\_LMP_{h}^{m,t} - PD\_LMP_{h}^{m,pdm}\ ,\right) \times Max\left(PD\_QSI_{k,h}^{m,pdm}\ /12 - Max\left(AQEI_{k,h}^{m,t}, DAM\_QSI_{k,h}^{m}/12\right), 0\ \right)\right]$$

Otherwise, if the *market participant* provides more than 4 hours of notice ahead of a given failure, then the Generator Failure Charge – Market Price Component formula is calculated as:

$$GFC\_MPC_{k,h}^{m} = \sum^{T} Min\left[0, -1 \times \left(Min\left(RT\_LMP_{h}^{m,t}, PD\_LMP_{h}^{m,pd1}\right) - PD\_LMP_{h}^{m,pdm}\right) \times Max\left(PD\_QSI_{k,h}^{m,pdm}/12 - Max\left(AQEI_{k,h}^{m,t}, DAM\_QSI_{k,h}^{m}/12\right), 0\right)\right]$$

Where:

‘T’ is the set of all Failure Intervals at *delivery point* ‘m’ in *settlement hour* ‘h’.

3.7.11.6 Generator Failure Charge - Guarantee Cost Component (GFC_GCC)

The guarantee cost component of the GFC represents an approximation of the guarantee cost of the replacement *generation unit*, if applicable. A failure charge will not result in a payment to a *market participant*.

For physical units, the GFC_GCC for a given failure will be calculated for the entire set of Failure Intervals associated with that failure (as defined in Table 3-65). If there are multiple isolated failures in one day, then the failure charge will be calculated for each failure. The GFC_GCC will be calculated using *offers*, prices and advisory schedules at the time of the latest binding commitment as well as DAM schedules and RT injections.

The calculation uses the operating profit function described in Section 3.7.1: DAM Make-Whole Payment (DAM_MWP) and in *IESO market rules* Section 9.3.8A.2.

GFC – Guarantee Cost Component Formula:

For a given failure ‘f’:

If the PD commitment bridges with a DAM commitment and PD advancement hours < MGBRT + MGBDT, then

$$SU\_INCR_{k,f}^{m} = Max\left(0, PD\_BE\_SU_{k,f}^{m,pdm} - DAM\_BE\_SU_{k,f}^{m}\right)$$

Else:

$$SU\_INCR_{k,f}^{m} = PD\_BE\_SU_{k,f}^{m,pdm}$$

Where:

‘$SU\_INCR_{k,f}^{m}$’ as defined in Section 3.5.5 Table 3-24.

‘$PD\_BE\_SU_{k,f}^{m,pdm}$’ as defined in Section 3.5.5 Table 3-25.

‘$DAM\_BE\_SU_{k,f}^{m}$’ as defined in Section 3.5.4 Table 3-15.

For intervals the resource failed to be at MLP during the PD MGBRT period, a prorated start-up offer will be included in the failure charge calculation. Where the prorated factor is calculated as:

$$PD\_SU\_MLP_{k,f}^{m} = Min\left(1, MLP\_INJ_{k,f}^{m} / PD\_MGBRT_{k,f}^{m}\right)$$

Where:

‘$PD\_SU\_MLP_{k,f}^{m}$’ as defined in Section 3.5.5 Table 3-24.

‘$MLP\_INJ_{k,f}^{m}$’ as defined in Section 3.5.5 Table 3-24.

‘$PD\_MGBRT_{k,f}^{m}$’ as defined in Section 3.5.5 Table 3-24.

$$GFC\_GCC_{k,f}^{m} = -1 \times Max\left(0, PD\_SU\_MLP_{k,f}^{m} \times SU\_INCR_{k,f}^{m,pdm} + \sum^{T}\left[PD\_BE\_SNL_{k,h}^{m,pdm}\right]/12 - \sum^{T}\left[OP\left(PD\_LMP_{h}^{m,pdm}, PD\_QSI_{k,h}^{m,pdm}, PD\_BE_{k,h}^{m,pdm}\right)/12\right]\right) \times M1$$

$$M1 = (1 - \sum^{T} Max(AQEI_{k,h}^{m,t}, DAM\_QSI_{k,h}^{m}/12) / \sum^{T} PD\_QSI_{k,h}^{m,pdm} /12)$$

Where:

'T'	represents the failure intervals as defined in Table 3-65.
'f'	represents the failure as defined in Table 3-65.
M1	is the pro-rating factor based on the amount of MW not delivered.
'$PD\_SU\_MLP_{k,f}^{m}$'	as defined in Section 3.5.5 Table 3-24.
'$SU\_INCR_{k,f}^{m,pdm}$'	as defined in Section 3.5.5 Table 3-24.

3.7.11.7 Pseudo-Unit Settlement for Generator Failure Charge Components

GFC for *pseudo-units* will be assessed on the physical *generation unit* basis for the combustion turbine and steam turbine associated with a *pseudo-unit*. The triggers for calculating GFC for *pseudo-units* are similar to those for an NQS *generation unit* associated with a physical unit. The interactions and considerations for the physical unit will apply to *pseudo-units* as well.

3.7.11.8 Triggers

CT Associated with a Pseudo-Unit

For a CT associated with a PSU, if the CT has either (1) a real-time *dispatch* schedule below its MLP, or (2) an activated single cycle flag at any time during an hour where there is an MLP operational constraint on the associated PSU resulting from a PD commitment, and the unit has increased its *offer* as in response to running as a single cycle unit, the failure charge calculation will be triggered. Scenarios include:

- the CT fails to ramp to its MLP on schedule;
- the CT fails to operate until the end of the commitment period of its associated PSU, including any extensions to the unit commitment occurring in PD;
- the CT fails to operate at all; or
- the associated PSU activates its single-cycle flag at any time during its commitment period or an extension of its commitment period and the unit has increased its price in response to the change in operating mode.

ST Associated with a Pseudo-Unit

For an ST associated with a PSU, the GFC will be triggered whenever one or more of the CTs associated with the ST has either (1) a real-time dispatch schedule below its respective MLP, or (2) its single-cycle flag activated, at any time during an hour where there is an MLP operational constraints, resulting from a PD commitment, on the PSU associated with the CT. Scenarios include:

- one or more of the CTs associated with the ST fails to ramp to its MLP on schedule;

- one or more of the CTs associated with the ST fails to operate until the end of the commitment period of its associated PSU, including any extensions to the unit commitment occurring in PD;
- one or more of the CTs associated with the ST fails to operate at all; or
- one of more of the PSUs associated with the ST activates its single cycle flag at any time during its commitment period over an extension of its commitment period.

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

CT Associated with a Pseudo-Unit

Depending on the time that the CT fails to reach its MLP or begins to operate in a single-cycle mode, the set of intervals deemed 'Failure Intervals' will vary. The following table lists the types of failure and the resulting sets of Failure Intervals.

Table 3-66: Types of Failure and Periods Subject to Failure Charge Assessment for a Pseudo-Unit

Type of Failure	Failure Intervals
The CT fails to operate at all	All hours where the PSU associated with the CT has a schedule at or above MLP in the PD advisory schedule issued at the time of binding start-up instruction.
The CT fails to reach its MLP on time	From the first interval where the PSU associated with the CT has an operational constraint resulting from a PD commitment, until the last interval where the CT has a real-time schedule below its MLP.
The unit operates in combined cycle mode but the CT fails to inject at or above its MLP for the duration of the associated PSU's MGBRT commitment	From the first interval where the CT has a real-time schedule below its MLP, until the last hour where the associated PSU's PD advisory schedule issued at BSUI is greater than or equal to the PSU's MLP.
The unit operates in combined cycle mode but the CT fails to inject at or above its MLP for the duration of an extension commitment made by the associated PSU, where that extension period is still within the PSU's original PD advisory schedule issued at the time of BSUI	From the first interval where the CT has a real-time schedule below its MLP, until the earlier of: • the end of the associated PSU's PD advisory schedule issued at the time of BSUI; or • the end of the associated PSU's PD advisory schedule at the time of extension
The unit operates in combined cycle mode but the CT fails to inject at or above its MLP for the duration of an extension commitment made by the associated PSU, where that extension period is outside of the original PD advisory schedule issued at the time of BSUI	From the first interval where the CT has a real-time schedule below its MLP, until the end of the associated PSU's operational constraint for PD commitment.
The unit switches to single cycle mode after it is committed by the PD engine in combined cycle mode	CT: From the first interval where the unit operates in single cycle mode and the *offer* has been increased, until the last hour where the associated PSU's PD

Type of Failure	Failure Intervals
	advisory schedule issued at BSUI is greater than or equal to the PSU's MLP. ST: From the first interval where the unit operates in single cycle mode, until the last hour where the associated PSU's PD advisory schedule issued at BSUI is greater than or equal to the PSU's MLP.

ST Associated with a Pseudo-Unit

For an ST associated with a PSU, the Generator Failure Charge – Market Price Component will be assessed on an hourly basis. It will calculate a charge for every interval within that hour that is classified as a Failure Interval, as defined by Table 3-66.

The Generator Failure Charge – Guarantee Cost Component (GFC_GCC), will be assessed across a period referred to as the GFC Calculation Period. The GFC Calculation Period is explained in more detail in the Pseudo-Unit Settlement – GFC_GCC section. For the GFC_MPC and the GFC_GCC, an interval will be considered a Failure Interval for the ST if the unit is operating as single cycle mode in the interval or that interval is considered a Failure Interval for one or more of its associated CTs.

3.7.11.10 Pseudo-Unit Settlement – GFC_MPC

CT Associated with a Pseudo-Unit

If the *market participant* provided less than 4 hours of notice ahead of a given failure, then the Generator Failure Charge – Market Price Component (GFC_MPC) formula is calculated as:

$$GFC\_MPC_{k,h}^{c} = \sum^{T} Min\left[0, (-1) \times \left(RT\_LMP_{h}^{c,t} - PD\_LMP_{h}^{c,pdm}\right) \times Max\left(PD\_QSI_{k,h}^{c,pdm}/12 - Max\left(AQEI_{k,h}^{c,t}, DAM\_QSI_{k,h}^{c}/12\right), 0\right)\right]$$

Otherwise, if the *market participant* provided more than 4 hours of notice ahead of the failure(s) included in GFC Calculation Period 'f', then the GFC_MPC formula is calculated as:

$$GFC\_MPC_{k,h}^{c} = \sum^{T} Min\left[0, (-1) \times \left(Min\left(RT\_LMP_{h}^{c,t}, PD\_LMP_{h}^{c,pd1}\right) - PD\_LMP_{h}^{c,pdm}\right) \times Max\left(PD\_QSI_{k,h}^{c,pdm}/12 - Max\left(AQEI_{k,h}^{c,t}, DAM\_QSI_{k,h}^{c}/12\right), 0\right)\right]$$

Where:

'T'	is the set of all Failure Intervals in *settlement hour* 'h'.

ST Associated with a Pseudo-Unit

The equation for an ST must consider the possibility that multiple PSUs maybe scheduled and fail at the same time:

When multiple PSU failures coincide in the same failure interval, the relevant PD commitment and binding PD schedule for each PSU may not necessarily have been issued in the same hour. As a result, there is no single PD_LMP value that should definitively be used in this calculation. In this case, the PD_LMP used in GFC_MPC calculation will be the minimum of the set of PD_LMP values calculated by PD runs that issued the most recent binding start-up instructions or commitment extensions of all PSUs whose associated CTs have a failure interval coincide with that ST failure interval.

When multiple PSUs associated with the ST are scheduled in a given interval and one or more of them incurred a failure in that same failure interval, the PD schedule used in the MPC failure charge calculation will be the sum of ST portion of the relevant PD schedule from each PSUs that failed its PD commitment.

For the remaining pseudo units that are online and do not incur a PD commitment failure, the ST portion of their real-time dispatch schedule will be considered as a MW quantity that is delivered and together with the PD schedule from the failed unit, as the MW expected to be delivered, which will be used to offset the actual injection from the ST unit.

The GFC_MPC for an ST associated with a PSU will be calculated for each individual ST Failure Interval and then summed across all ST Failure Intervals in each hour.

$$GFC\_MPC_{k,h}^{s} = \sum^{T_h} GFC\_MPC_{k,h}^{s,t}$$

Where:

‘T_h’	is the set of all ST Failure Intervals in *settlement hour* ‘h’.

For a given ST Failure Interval, if the *market participant* provides less than 4 hours of notice ahead of any of the failures within the interval, the GFC_MPC will be calculated as follows:

$$GFC\_MPC_{k,h}^{s,t} = (-1) \times Max\left(RT\_LMP_h^{s,t} - Min\left\{c \in CT_F \middle| PD\_LMP_h^{s,pdc}\right\}, 0\right) \times Max\left(\sum^{M_t}\left[RT\_STP\_QSI_{k,h}^{p,t}\right] + \sum^{N_t}\left[\frac{PD\_STP\_QSI_{k,h}^{p,pdc}}{12}\right] - AQEI_{k,h}^{s,t}, 0\right)$$

Otherwise, if the *market participant* provides more than 4 hours of notice ahead of the failure(s), then the GFC_MPC will be calculated as follows:

$$GFC\_MPC_{k,h}^{s,t} = (-1) \times Max\left(Min\left(RT\_LMP_h^{s,t}, PD\_LMP_h^{s,pd1}\right) - Min\left\{c \in CT_F \middle| PD\_LMP_h^{s,pdc}\right\}, 0\right) \times Max\left(\sum^{M_t}\left[RT\_STP\_QSI_{k,h}^{p,t}\right] + \sum^{N_t}\left[\frac{PD\_STP\_QSI_{k,h}^{p,pdc}}{12}\right] - AQEI_{k,h}^{s,t}, 0\right)$$

Where:

‘CT_F’	is the set of all CTs associated with ST ‘s’ having a CT Failure Interval coincide with *metering interval* ‘t’.
‘M_t’	is the set of all PSUs associated with the ST ‘s’, whose associated CT does not have a CT Failure Interval coinciding with *metering interval* ‘t’.
‘N_t’	is the set of all PSUs associated with the ST ‘s’, whose associated CT has a CT Failure Interval coinciding with *metering interval* ‘t’.
‘$RT\_STP\_QSI_{k,h}^{p,t}$’	as defined in Section 3.5.6 Table 3-35.
‘$PD\_STP\_QSI_{k,h}^{p,pdc}$’	as defined in Section 3.5.5 Table 3-26.

3.7.11.11 Pseudo-Unit Settlement – GFC_GCC

CT Associated with a Pseudo-Unit

The GFC_GCC for a given failure at a CT associated with a PSU will be calculated for the entire set of Failure Intervals associated with that failure as defined in Table 3-66. If there are multiple isolated failures in one day, then the GFC_GCC will be calculated for each failure. The GFC_GCC will be calculated using *offers*, price and advisory schedules at the time of commitment as well as DAM schedules and RT injections.

For a given failure ‘f’:

If the PD commitment violated by the failure ‘f’ bridges with a DAM commitment, and the number of PD advancement hours is less than the PSU’s MGBRT plus its MGBDT, then

$$SU\_INCR_{k,f}^{p,pdi} = Max\,(0, PD\_BE\_SU_{k,f}^{p,pdi} - DAM\_BE\_SU_{k,f}^{p})$$

Else:

$$SU\_INCR_{k,f}^{p,pdi} = PD\_BE\_SU_{k,f}^{p,pdi}$$

Where:

‘$SU\_INCR_{k,f}^{p,pdi}$’ as defined in Section 3.5.5 Table 3-24.

For intervals that CT failed to be at MLP during the PD MGBRT period, a prorated start-up offer will be included in the failure charge calculation. Where the prorated factor is calculated as:

$$PD\_SU\_MLP_{k,f}^{c} = Min\left(1, \frac{MLP\_INJ_{k,f}^{c}}{PD\_MGBRT_{k,f}^{c}}\right)$$

Where:

‘$PD\_SU\_MLP_{k,f}^{c}$’ as defined in Section 3.5.5 Table 3-24.

‘$MLP\_INJ_{k,f}^{c}$’ as defined in Section 3.5.5 Table 3-24.

‘$PD\_MGBRT_{k,f}^{c}$’ as defined in Section 3.5.5 Table 3-24.

$$\begin{aligned} GFC\_GCC_{k,f}^{c} = (-1) \\ \times Max\Bigg[0, PD\_SU\_MLP_{k,f}^{c} \times SU\_INCR_{k,f}^{p,pdi} \times \left(1 - ST\_Portion_{k,d1}^{p}\right) \\ + \sum^{T}\Bigg(\frac{PD\_BE\_SNL_{k,h}^{p,pdc}}{12} \times \left(1 - ST\_Portion_{k,d1}^{p}\right) \\ - \frac{OP\left(PD\_LMP_{h}^{c,pdm}, PD\_QSI_{k,h}^{c,pdm}, GFC\_GCC\_DIPC_{k,h}^{c,t}\right)}{12}\Bigg)\Bigg] \times M1 \end{aligned}$$

$$M1 = \left[1 - \frac{\sum^{T} Max\left(AQEI_{k,h}^{c,t}, \frac{DAM\_QSI_{k,h}^{c}}{12}\right)}{\left(\frac{\sum^{T} PD\_QSI_{k,h}^{c,pdm}}{12}\right)}\right]$$

Where:

'T'	is the set of all failure *metering intervals* 't' associated with failure 'f'.
'M1'	is the pro-rating factor based on the amount of MW not delivered.
'$PD\_SU\_MLP_{k,f}^{c}$'	as defined in Section 3.5.5 Table 3-24.
'$SU\_INCR_{k,f}^{p,pdi}$'	as defined in Section 3.5.5 Table 3-24.
'DIPC'	GFC variables with 'DIPC' are defined in Section 3.5.5 Table 3-26.
'$ST\_Portion_{k,d1}^{p}$'	as defined in Section 3.5.9 Table 3-37.

ST Associated with a Pseudo-Unit

The GFC_GCC for an ST associated with a PSU will be assessed across a period referred to as the GFC Calculation Period. The GFC Calculation Period is a contiguous block of ST Failure Intervals that which is bound on either end by an interval, which is not classified as an ST Failure Interval.

The GFC Calculation Period:

- may relate to a single standalone block of CT Failure Intervals, if there were only one isolated failure at a single CT associated with the ST; or
- may relate to multiple overlapping failures, if there are multiple CTs associated with a given ST. In this case, the contiguous block of ST Failure Intervals may not overlap entirely with a block of CT Failure Intervals from a single CT.

The charge will be calculated for the entire GFC Calculation Period 'x'. If there are multiple unbridged ST failures in one day, the failure charge will be calculated for each separate GFC Calculation Period.

Additionally, in order to achieve consistent *settlement* treatment, the GFC_GCC calculation for an ST associated with a PSU will require a set of DIPC/DIGQ variables that are specifically designed for this calculation. The GCC_DIPC and GCC_DIGQ are derived from pre-dispatch *offers* and *pre-dispatch schedules* for PSUs whose CTs have Failure Intervals coinciding with the *metering interval* in question. For each PSU included in the calculation, the PD *offers* and schedules will be drawn from the appropriate PD run that issued the operational constraint that was violated by the failure in question.

For a given failure 'f':

For each PSU 'p' associated with ST 's', whose associated CT 'c' has a failure 'f' overlapping with the ST GFC Calculation Period 'x', the ST portion of that PSU's start-up offers will be calculated as follows:

If the CT's PD commitment bridges with a DAM commitment, and the number of PD Advancement hours is less than the PSU's MGBRT plus its MGBDT, then

$$STP\_SU\_INCR_{k,f}^{p,pdi} = Max\left(0, PD\_BE\_SU_{k,f}^{p,pdi} - DAM\_BE\_SU_{k,f}^{p}\right) \times ST\_Portion_{d1}^{p}$$

Else:

$$STP\_SU\_INCR_{k,f}^{p,pdi} = PD\_BE\_SU_{k,f}^{p,pdi} \times ST\_Portion_{d1}^{p}$$

Where:

'$STP\_SU\_INCR_{k,f}^{p,pdi}$'	as defined in Section 3.5.5 Table 3-24.

'$\text{ST\_Portion}^{p}_{k,d1}$' as defined in Section 3.5.9 Table 3-37.

The variable $\text{PD\_SU\_MLP}^{c}_{k,f}$ will be calculated as follows for each CT failure 'f', that overlaps with the ST's GFC Calculation Period 'x'.

$$\text{PD\_SU\_MLP}^{c}_{k,f} = Min\left(1, \frac{MLP\_INJ^{c}_{k,f}}{PD\_MGBRT^{c}_{k,f}}\right)$$

Where:

'$\text{PD\_SU\_MLP}^{c}_{k,f}$'	as defined in Section 3.5.5 Table 3-24.
'$\text{MLP\_INJ}^{c}_{k,f}$'	as defined in Section 3.5.5 Table 3-24.
'$\text{PD\_MGBRT}^{c}_{k,f}$'	as defined in Section 3.5.5 Table 3-24.

$$\begin{aligned} &GFC\_GCC^{s}_{k,x} \\ &= (-1) \\ &\times Max\left[0, \sum^{F}\left(PD\_SU\_MLP^{c}_{k,f} \times STP\_SU\_INCR^{p,pdi}_{k,f}\right)\right. \\ &+ \sum^{T}\sum^{CF_t}\left(\frac{PD\_BE\_SNL^{p,pdc}_{k,h}}{12} \times ST\_Portion^{p}_{k,d1}\right) \\ &\left. - \sum^{T}\left(OP\left[Min\left\{c \in CT_F \,\middle|\, PD\_LMP^{s,pdc}_{h}\right\}, GFC\_GCC\_DIGQ^{s,t}_{k,h}, GFC\_GCC\_DIPC^{s,t}_{k,h}\right]/12\right)\right] \times M1 \end{aligned}$$

$$M1 = \left[1 - \frac{\sum^{T}\left[AQEI^{s,t}_{k,h} - \sum^{M_t}\left(RT\_STP\_QSI^{p,t}_{k,h}\right)\right]}{\sum^{T}\sum^{N_t}\left[\frac{PD\_STP\_QSI^{p,pdc}_{k,h}}{12}\right]}\right]$$

Where:

'F'	is the set of all CT failures 'f' occurring within the ST GFC Calculation Period 'x'.
'T'	is the set of all *metering intervals* in ST GFC Calculation Period 'x'.
'CF_{t}'	is the set of all CTs associated with ST 's' having a CT Failure Interval coincide with *metering interval* 't'.
'M_{t}'	is the set of all PSUs associated with the ST 's', whose associated CT does not have a CT Failure Interval coinciding with *metering interval* 't'.
'N_{t}'	is the set of all PSUs associated with the ST 's', whose associated CT does have a CT Failure Interval coinciding with *metering interval* 't'.
'$\text{PD\_SU\_MLP}^{c}_{k,f}$'	as defined in Section 3.5.5 Table 3-24.
'$\text{STP\_SU\_INCR}^{p,pdi}_{k,f}$'	as defined in Section 3.5.5 Table 3-24.
'$\text{ST\_Portion}^{p}_{k,d1}$'	as defined in Section 3.5.9 Table 3-37.
'$\text{RT\_STP\_QSI}^{p,t}_{k,h}$'	as defined in Section 3.5.6 Table 3-24.
'$\text{PD\_STP\_QSI}^{p,pdc}_{k,h}$'	as defined in Section 3.5.5 Table 3-24.

'DIPC'	GFC variables with 'DIPC' are defined in Section 3.5.5 Table 3-26.
'DIGQ'	GFC variables with 'DIPC' are defined in Section 3.5.5 Table 3-26.

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

The Generator Failure Charge Uplift (GFCU) is intended to return the failure charge collected from a *generation unit* that fails to fulfill its PD commitment to the market.

The Generator Failure Charge - Market Price Component Uplift (GFC_MPCU) will be allocated on a pro-rata basis to all *real-time market* loads and exports on an hourly basis.

The formulation of the GFC_MPCU is as follows:

$$GFC\_MPCU_{k,h} = \sum_{K}^{M} GFC\_MPC_{k,h}^{m} \times \left[\sum^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t} + RQ_{k,h}^{m,i,t}) / \sum_{K}^{M,T} \left(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}\right)\right]$$

Where

'K'	is the set of all *market participants* 'k'.
'M'	is the set of all *delivery points* 'm' and *intertie metering points* 'i'.
'T'	is the set of all *metering intervals* 't' in *settlement hour* 'h'.

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

The Generator Failure Charge –Guarantee Cost Component Uplift (GFC_GCCU) is intended to return the failure charge collected from a *generation unit* that fails to fulfill its PD commitment to the market.

The GFC_GCCU will be allocated on a pro-rata basis to all *real-time market* loads and exports on a daily basis. The GFC_GCCU will be uplifted on a daily basis because the GFC_GCC is calculated over a failure period that may extend beyond an hour.

The formulation of the GFC_GCCU is as follows:

$$\mathrm{GFC\_GCCU}_{k} = \sum_{K,F}^{M} \mathrm{GFC\_GCC}_{k,f}^{m} \text{ x } [\sum_{H}^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}) / \sum_{K,H}^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t})]$$

Where:

'M'	is the set of all *delivery points* 'm' and *intertie metering points* 'i'.
'K'	is the set of all *market participants* 'k'.
'F'	represents the failure as defined in Table 3-65.
'T'	is the set of all *metering intervals* 't' in *settlement hour* 'h'.
'H'	Is the set of all *settlement hours* 'h' in the *trading day*.

3.7.14 Congestion Rent and Loss Residuals (CRLR)

Residuals are created in all *electricity markets* that have locational pricing. In a two-*settlement* system, residuals from congestion rent and marginal loss will be collected in both the day-ahead market and the *real-time market*.

Congestion rent and loss residuals (CRLR) collected at internal system nodes will be disbursed to all loads on a pro-rata basis across all allocated quantities of *energy* withdrawn at all *RWMs*. Congestion rents collected due to *intertie* congestion will continue to be available to the *TR clearing account* to fund *TRs*.

CRLR is the total residual collected by the *IESO* within the *energy market billing period* that is available for distribution to all loads such that:

CRLR = [term1] + [term2] + [term3] + [term4] – [term5]

[**term1]**	congestion rent and marginal loss accrued in the DAM and the *real-time market* to settle all *generators*, *dispatchable loads* and price responsive loads
+ [**term 2]**	congestion rent and marginal loss accrued in the DAM and the *real-time market* to settle virtual transactions
+ [**term 3]**	congestion rent and marginal loss accrued to settle NDLs
+ [**term 4]**	congestion rent and marginal loss to settle *boundary entities*
- [**term 5]**	congestion rent collected on *interties* when *interties* are either import-congested or export-congested]

$$CRLR = \sum_{H}^{M}\Big[\big(DAM\_QSW_{k,h}^{m} - DAM\_QSI_{k,h}^{m}\big)\ x\ DAM\_LMP_{h}^{m}$$
$$+ \sum^{T}\Big(\big(AQEW_{k,h}^{m,t} - AQEI_{k,h}^{m,t}\big) - \big(DAM\_QSW_{k,h}^{m} - DAM\_QSI_{k,h}^{m}\big)/12\Big)\ x\ RT\_LMP_{h}^{m,t}\Big]$$
$$+ \sum_{H}^{V}\Big[\big(DAM\_QVSW_{k,h}^{v} - DAM\_QVSI_{k,h}^{v}\big)\ x \sum^{T}\big(DAM\_LMP_{h}^{v} - RT\_LMP_{h}^{v,t}\big)\,()\,)\Big]$$
$$+ \sum_{H}^{M1}\Big[\big(DAM\_LMP_{h}^{z} + LFDC_{h}\big)\ x \sum^{T} AQEW_{k,h}^{m,t}\Big]$$

$$+ \sum_{H}^{I}\Big[\big(DAM\_QSW_{k,h}^{i} - DAM\_QSI_{k,h}^{i}\big)\ x\ DAM\_LMP_{h}^{i}$$
$$+ \sum^{T}\Big(\big(SQEW_{k,h}^{i,t} - SQEI_{k,h}^{i,t}\big)$$
$$- \big(DAM\_QSW_{k,h}^{i} - DAM\_QSI_{k,h}^{i}\big)/12\ x\ ISP_{h}^{i,t}\Big)\Big]$$
$$- \sum_{H}^{I}\Big[\big(DAM\_QSW_{k,h}^{i} - DAM\_QSI_{k,h}^{i}\big)\ x\ DAM\_ICP_{h}^{i}$$
$$+ \sum^{T}\Big(\big(SQEW_{k,h}^{i,t} - SQEI_{k,h}^{i,t}\big)$$
$$- \big(DAM\_QSW_{k,h}^{i} - DAM\_QSI_{k,h}^{i}\big)/12\ x\ RT\_ICP_{h}^{i,t}\Big)\Big]$$

Where:

‘M’	Is the set of all *RWMs* ‘m’ except *non-dispatchable loads.*
‘M1’	is the set of all *RWMs* ‘m’ relating to *non-dispatchable loads.*
‘H’	is the set of all *settlement hours* ‘h’.
‘T’	is the set of all *metering intervals* ‘t’ in *settlement hour* ‘h’.
‘V’	is the set of all virtual transaction zonal trading entities relating to virtual loads and virtual suppliers.
‘I’	is the set of all *intertie metering points* ‘i’.
‘$ISP_h^{i,t}$’	as defined in Section 3.5.6 Table 3-27.

3.7.14.1 CRLR Disbursement (CRLRD)

CRLR will be calculated and disbursed to loads on a monthly basis according to the allocated quantity of *energy* withdrawn by the load at each *RWM* during the *energy market billing period.*

The formula for disbursement of congestion rent and loss residuals (CRLRD) is as follows:

$$CRLRD_k = CRLR \times \sum_{H}^{M,T} (AQEW_{k,h}^{m,t}) \,/\, \sum_{K,H}^{M,T} (AQEW_{k,h}^{m,t})$$

Where:

‘M’	is the set of all *RWMs* ‘m’ relating to *non-dispatchable loads*, *dispatchable loads* and price responsive loads.
‘H’	is the set of all *settlement* hours ‘h’ in the *settlement billing period.*
‘T’	is the set of all the *metering intervals* ‘t’ in *settlement hour* ‘h’.
‘K’	is the set of all *market participants* ‘k’.

3.7.15 Transmission Rights

As a result of the introduction of LMPs and a DAM, conforming changes will be required for the financial *TR market*. The *IESO* will incorporate LMPs and shift *TR market settlement* from real-time to day-ahead.

Under a separate initiative from MRP, the *IESO* is undertaking a review of Ontario’s Transmission Rights (TR) market.

The review will assess the objectives and benefits of Ontario’s *TR market*, to identify potential improvements, and to ensure compatibility and alignment with the future renewed *energy market*.

Upon completion of the TR Market Review, *settlement amounts* will be determined for the future *TR market*.

The TR Market Review will address where and how the real-time *intertie* congestion will be collected and settled.

3.7.16 Impacted Current Settlement Amounts

3.7.16.1 Changes to the Operating Reserve Shortfall Settlement Debit

The Operating Reserve Shortfall *Settlement* Debit (ORSSD) is a mechanism described in Chapter 9, Section 3.8 of the *Market Rules*. This mechanism gives the *IESO* the ability to retroactively adjust the Operating Reserve Settlement Credits (ORSC) paid to a *registered facility* that is deficient in meeting a call to provide *operating reserve*. For the most part, such issues have been handled as a compliance matter outside of the *settlement process* since market opening. Regardless of any future policy concerning the usage of this mechanism, the description provided in the *market rules* will continue to be aligned with the way in which *operating reserve* payments will be credited *to market participants*.

In the future market, ORSSD will be accounted for in the formulation of the DAM_MWP and the RT_MWP *settlement amounts*. Changes will be made to the DAM_MWP and RT_MWP after the ongoing stakeholder engagement "Improving Accessibility of Operating Reserve" is complete.

The current formulation for ORSSD will be revised to remove congestion management *settlement* credits (CMSC) and will include only second *settlement* HORSA{2} *amounts*. The current *settlement amount* ORSSD with be replaced with RT_ORSD, and the associated uplift will be RT_ORSDU.

All *settlement amounts* are specific to the *facility* for which the RT_ORSD is being assessed.

3.7.16.2 Changes to Generation Station Service Rebate (GSSR)

Under the current *market rules*, if physical *energy* withdrawn from the *real-time market* qualifies as *generation station service* and the associated *generation facility* is a net injector into the *IESO-administered markets*, that *generation facility* is eligible for a monthly rebate on all the uplift payments it incurs from the *generation station service*.[6]

Applying the same principles to DAM, the *settlement process* will need to support rebate claims for the following DAM uplift amounts that are allocated in the second *settlement* using the same formula as in today's *real-time market*:

- DAM Operating Reserve Uplift;
- DAM Reliability Scheduling Uplift;
- DAM Balancing Credit Uplift; and
- DAM Make-Whole Payment Uplift.

In addition to new DAM uplifts, and existing uplifts from the current market, there will be new uplifts in real time that the *settlement process* will need to support rebate claims for, which include:

- Real-Time Make-Whole Payment Uplift;
- Real-Time Ramp-Down Settlement Amount Uplift;
- Reference Level Settlement Charge Uplift;
- Real-Time Generator Offer Guarantee Uplift;
- Generator Failure Charge – Market Price Component Uplift;
- Generator Failure Charge – Guarantee Cost Component Uplift; and
- Real-Time Intertie Failure Charge Uplift.

[6] Some exemptions apply – see Chapter 9, Section 2.1A of the *Market Rules* for further details.

As per the existing *market rules*, the methodology for determining eligibility and claiming the rebate are subject to the applicable *market manuals*.

3.7.16.3 Changes to Real-Time Intertie Failure Charges (RT_INFC)

General Description

All changes to the real-time *intertie* failure charges (RT_INFC) are based on a schedule set one hour in advance of the *real-time market settlement hour* as part of the *IESO pre-dispatch scheduling* process. Changes are required to address which schedules are subject to the RT_INFC and the internal node LMP equivalent to the LMP at the *intertie* node. In the future market, *intertie* failure charges will not be applied to an *intertie* transaction when the *pre-dispatch schedule* is less than or equal to the DAM schedule. The RT_INFC will apply to an *intertie* transaction for the portion of the *pre-dispatch schedule* that is greater than the DAM schedule and is not scheduled in real time. The RT_INFC will apply when the *pre-dispatch scheduled* amount fails to be scheduled in real time for a reason within the participant's control.

The internal node LMP will be used to calculate the RT_INFC instead of the Ontario *market clearing price* (MCP). The internal node LMP will more accurately represent the impact an *intertie* failure had on the price at the *intertie*. The *intertie* failure charge calculation will not include the net interchange scheduling limit price (NISL) and *intertie congestion price* (ICP). A price bias exists in today's market to account for different methods used to calculate the pre-dispatch and real-time prices. In the future market, a price bias continues to be necessary to account for the different methods. A new set of *settlement amounts* will be necessary for the RT failure charges. A new uplift *settlement amount* will be necessary to reflect that the failure charges are only applied in real time.

An *intertie* transaction will be exempted from the *intertie* failure charge in the event that the failure is for reasons outside the *market participant's* control.

Table 3-67: Resolution of Real-Time Intertie Failure Charge Calculation

Attribute	Resolution
Time resolution	Hourly
Geographic resolution	Imports and Exports: • By *delivery point* • By *intertie metering point*
Price accuracy (RT & PD)	$/MWh to the nearest cent
RT, PD & DA energy quantities	MW schedule values converted to MWh values for the purposes of *settlement,* rounded to the nearest 0.1 MWh per hour or per 5-minute *metering interval*
All *real-time market settlement* data	Includes: Schedule data at *intertie metering points*
Price Bias	$/MW to the nearest cent

RT-Import Failure Charge (RT_IMFC) – Formula:

$$RT\_ISD_{k,h}^{i,t} = MAX(MAX\,(PD\_QSI_{k,h}^{i}/12 - DAM\_QSI_{k,h}^{i}/12, 0) - MAX(SQEI_{k,h}^{i,t} - DAM\_QSI_{k,h}^{i}/12, 0), 0\,)$$

$$RT\_IMFC_{k,h}^{i} = \sum^{T} (-1) \times MIN\ (MAX\ (0, (RT\_LMP_{h}^{m,t} + PB\_IM_{h}^{t} - PD\_LMP_{h}^{m}/12) \times RT\_ISD_{k,h}^{i,t}), MAX\ (0, RT\_LMP_{h}^{m,t} \times RT\_ISD_{k,h}^{i,t}))$$

Where:

'm'	is the set of all *delivery points* 'm' that are the internal node equivalent to the *intertie metering point* 'i'.
'T'	is the set of all the *metering intervals* 't' in *settlement hour* 'h'.
'$PB\_IM_{h}^{t}$'	as defined in Section 3.5.6 Table 3-32.
'$RT\_ISD_{k,h}^{i,t}$'	as defined in Section 3.5.6 Table 3-32.

RT-Export Failure Charge (RT_EXFC) – Formula:

$$RT\_ESD_{k,h}^{i,t} = MAX(MAX\ (PD\_QSW_{k,h}^{i}/12 - DAM\_QSW_{k,h}^{i}/12, 0) - MAX(SQEW_{k,h}^{i,t} - DAM\_QSW_{k,h}^{i}/12, 0), 0\ )$$

$$RT\_EXFC_{k,h}^{i} = \sum^{T} (-1) \times MIN\ (MAX\ (0, (PD\_LMP_{h}^{m}/12 - PB\_EX_{h}^{t} - RT\_LMP_{h}^{m,t}) \times RT\_ESD_{k,h}^{i,t}), MAX\ (0,\ PD\_LMP_{h}^{m}\ /12 \times\ RT\_ESD_{k,h}^{i,t}))$$

Where:

'm'	is the set of all *delivery points* 'm' that are the internal node equivalent to the *intertie metering point* 'i'.
'T'	is the set of all the *metering intervals* 't' in *settlement hour* 'h'.
'$PB\_EX_{h}^{t}$'	as defined in Section 3.5.6 Table 3-32.
'$RT\_ESD_{k,h}^{i,t}$'	as defined in Section 3.5.6 Table 3-32.

3.7.16.4 Real-Time Intertie Failure Charge Uplift (RT _INFCU)

General Description

The Real-Time Intertie Failure Charge Uplift (RT _INFCU) is intended to reimburse the failure charge collected from imports and exports.

The RT_INFCU will be allocated on a pro-rata basis to all *real-time market* loads and exports on an hourly basis.

Formula

The formulation of the RT INFCU is as follows:

$$RT\_INFCU_{k,h} = \sum_{K}^{I} (RT\_IMFC_{k,h}^{i} + RT\_EXFC_{k,h}^{i}) \times \left[\sum^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t} + RQ_{k,h}^{m,i,t}) / \sum_{K}^{M,T} \left(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}\right)\right]$$

Where:

'K'	is the set of all *market participants* 'k'.
'M'	is the set of all *delivery points* 'm' and *intertie metering points* 'i'.

'I'	is the set of all *intertie metering points* 'i'.
'T'	is the set of all *metering intervals* 't' in *settlement hour* 'h'.
'$RQ_{k,h}^{m,i,t}$'	as defined in Section 3.5.6 Table 3-36.

3.7.16.5 Changes to Real-Time Intertie Offer Guarantee (RT_IOG) and IOG Offset

General Description

The current real-time *intertie offer* guarantee (RT_IOG) is required to ensure that import transactions scheduled in the *real-time market* have the appropriate incentive to follow *dispatch instructions* for *reliability* reasons. RT_IOG ensures that *market participants* will not face a negative operating profit during the hour in which the import transaction is scheduled to flow. The RT_IOG is subject to the IOG offsets.

The RT_IOG, including the IOG offset mechanism, will continue to *settle* real-time import transactions on the basis of an *intertie settlement* price and a schedule that is set one hour in advance of the *real-time market settlement hour*. The import transaction schedule will continue to be determined through the *IESO pre-dispatch scheduling* process, and the *intertie settlement* price for import transactions will be determined as described in the SSM high-level design document. Because the price at which the import transaction is scheduled in the *pre-dispatch scheduling* process may be different than the *real-time market price*, RT_IOG will still be required to ensure that import transactions have the appropriate incentive to follow *dispatch instructions*.

The current market also includes a day-ahead IOG for import transaction quantities scheduled by the DACP. This will not be required under the DAM because the DAM schedule is financially binding, which means that an import that follows its DAM schedule is not impacted by any price changes in PD or RT. Therefore, the formulation of the RT_IOG will ensure that it only applies to those import transaction quantities not scheduled in the DAM, including the incremental real-time import transaction quantity scheduled above the DAM schedule.

The IOG offset will continue to be applicable to the RT_IOG payments made to real-time import transactions that are part of an implied wheeling through transaction. The IOG offset will reverse RT_IOG payments to real-time import transactions offset by real-time exports, where no net power is provided to Ontario. The IOG offset will also apply to RT imports when the *market participant* has portions of the DAM import schedule that have not been scheduled in RT. A new RT_IOG uplift will be required in the future market.

The required changes to the IOG will be reflected in the preamble to Chapter 9, Section 3.8A of the *Market Rules*, and in the formulation of the IOG itself.

IOG Offset

The RT IOGs are subject to IOG offsets if the underlying import is part of an implied wheel-through transaction or the *market participant* has DAM imports not scheduled in real-time. The IOG offset is still relevant to the IOG payments made to real-time import transactions that are part of a wheeling through transaction.

IOG offsets will occur in a stacked, sequence based on their timeframe – either DAM or RT, and based on the proximity of the import to the offset quantity. The RT IOG offset is stacked based on a matrix of real-time import quantities arranged by RT IOG rate, in ascending order, compared to the offset quantities. The IOG offsets will be determined in three steps, starting from the narrowest view of an *intertie* to the broadest view of Ontario:

1. At the *intertie*:
    - Offset RT imports with DAM imports not scheduled in RT that are scheduled on the same *intertie*.
    - Offset remaining RT imports with RT exports that are scheduled on the same *intertie*.
2. At the jurisdiction:
    - Offset remaining RT imports with remaining DAM imports not scheduled in RT that are scheduled in the same jurisdiction.
    - Offset remaining RT imports with remaining RT exports that are scheduled in the same jurisdiction.
3. In Ontario:
    - Offset remaining RT imports with all remaining DAM imports not scheduled in RT.
    - Offset remaining RT imports with all remaining RT exports.

No import will receive more than a 100% offset. A jurisdiction is defined as a group of *interties* that can be independently scheduled and are part of one jurisdictional authority.

Table 3-68: Resolution of RT_IOG Calculation

Attribute	Resolution
Time resolution	Hourly
Geographic resolution	Imports: • By *intertie metering point*
RT price accuracy	$/MW to the nearest cent
DAM & RT energy quantities	MW schedule values converted to MWh values for the purposes of *settlement*, rounded to the nearest 0.1 MWh per hour or per 5-minute *metering interval*
All *real-time market settlement* data	Schedule data at *intertie metering points*

Formula

Using the operating profit function defined in Section 3.7.1: DAM Make-Whole Payment (DAM_MWP) and in *IESO market rules* Section 9.3.8A.2, the Real-Time Intertie Offer Guarantee (RT_IOG) *settlement amount* is derived as follows:

$$Potential\_IOG_{k,h}^{i} = \sum_I (-1) \times Min\left[0, \sum^T OP\left(ISP_h^{i,t}, SQEI_{k,h}^{i,t}, BE_{k,h}^{i,t}\right) - \sum^T OP\left(ISP_h^{i,t}, Min\left[SQEI_{k,h}^{i,t}, DAM\_QSI_{k,h}^{i}/12\right], BE_{k,h}^{i,t}\right)\right]$$

$$IOG\_Rate_{k,h}^{i} = Potential\_IOG_{k,h}^{i} / SQEI_{k,h}^{i,t}$$

Where:

'I'	is the set of all *intertie metering points* 'i'.
'T'	is the set of all *metering intervals* 't' during *settlement hour* 'h'.

'$ISP_{h}^{i,t}$' as defined in Section 3.5.6 Table 3-27.

Once the IOG offset has been determined for each RT import transaction, the net IOG can be calculated.

$$Net\_IOG_{k,h}^{i} = Max\left[Potential\_IOG_{k,h}^{i} - IOG\_Offset_{k,h}^{i}, 0\right]$$

3.7.16.6 Real-Time Intertie Offer Guarantee Uplift (RT_IOGU)

General Description

The RT_IOG Uplift is intended to distribute the cost of RT_IOG payments.

The RT_IOG Uplift will be allocated on a pro-rata basis to all *real-time market* loads and exports on an hourly basis.

Formula

The formulation of the RT_IOG Uplift is as follows:

$$RT\_IOGU_{k,h} = \sum_{K}^{I} Net\_IOG_{k,h}^{i} \times \left[\sum^{M,T}(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t} + RQ_{k,h}^{m,i,t}) \,/\, \sum_{K}^{M,T}\left(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}\right)\right]$$

Where:

'I' is the set of all *intertie metering points* 'i'.

'K' is the set of all *market participants* 'k'.

'M' is the set of all *delivery points* 'm' and *intertie metering points* 'i'.

'T' is the set of all *metering intervals* 't' during *settlement hour* 'h'.

'$RQ_{k,h}^{m,i,t}$' as defined in Section 3.5.6 Table 3-36.

3.7.16.7 Changes to Ramp-Down Settlement Amount

General Description

During ramp-down, NQS *generation units* may incur costs that are not recovered through applicable LMPs. Ramp-down costs, if not recovered through market revenues, are currently addressed through an out of market payment called the ramp-down *settlement* amount (RDSA).

In the future market, NQS *generation units* will receive *energy* revenue based on the applicable LMP during the ramp-down to come offline. The RT_MWP will not apply below MLP because it is assessed only when a resource is dispatched uneconomically, and *generation facilities* cannot respond to economic dispatches below MLP.

The *generation units* will continue to be compensated through the ramp-down *settlement amount* if the revenue received for hours where the resource is scheduled below MLP does not cover the cost incurred during the same hours. The ramp-down *settlement* payment will continue to use a generator-specific *offer* price taken from the hour before the hour ramp-down period begins, applying a standard fixed factor determined according to the *dispatch instruction* for the ramp-down intervals.

If a *generation unit* gets dispatched offline in the middle of their DAM schedule, the ramp-down *settlement* payment will offset the adjusted *offer* against the revenues received in day-ahead which includes DAM *energy* payment and DAM lost cost compensation at their real-time injection.

The RT_RDSA will incorporate any required adjustment and mitigation test results into the calculation set out by the market power mitigation process, which is described in Section 3.13: Market Power Mitigation.

Table 3-69: Resolution of RT_RDSA Calculation

Attribute	Resolution
Time resolution	Hourly
Geographic resolution	NQS *generation facilities* within Ontario: • By *delivery point*
RT price accuracy (*Energy* and OR)	$/MWh to the nearest cent
RT *energy* quantities	MW schedule values converted to MWh values for the purposes of *settlement*, rounded to the nearest 0.1 MWh per hour or 0.001 MWh per 5-minute *metering interval*
All *real-time market settlement* data	Includes: Revenue *metering data* at applicable *delivery points*

Formula

The calculation uses the operating profit function described in Section 3.7.1 – DAM Make-Whole Payment (DAM_MWP) and in *IESO market rules* Section 9.3.8A.2.

If the resource is coming offline during the period where resource has a DAM schedule:

$$RT\_RDSA_k^m = Max\left(0, \sum^T \left[(-1) \times OP\left(DAM\_LMP_h^m, AQEI_{k,h}^{m,t}, BE_{k,h}^{m,t}\right) + Max\left(0, (-1) \times OP\left(DAM\_LMP_h^m, AQEI_{k,h}^{m,t}, DAM\_BE_{k,h}^m\right)\right)\right]\right)$$

Otherwise:

$$RT\_RDSA_k^m = Max\left(0, \sum^T \left[(-1) \times OP\left(RT\_LMP_h^{m,t}, AQEI_{k,h}^{m,t}, BE_{k,h}^{m,t}\right)\right]\right)$$

Where:

‘T’ is the set of all *settlement* intervals ‘t’ beginning from the first interval that the *facility* is scheduled below MLP to come offline and ends when there is no *dispatch* or a zero MWh *dispatch instruction*.

‘$BE_{k,h}^{m,t}$’ as defined in Section 3.5.6 Table 3-33.

In this instance, $BE_{k,h}^{m,t}$ is a matrix of ‘n’ *price-quantity pairs offered* by *market participant* ‘k’ to supply *energy* during the *settlement hour* ‘h’ immediately before the hour in which ramp-down begins, where *price* is adjusted by a ramp-down factor (RDF).

3.7.16.8 Real-Time Ramp-Down Settlement Amount for Pseudo-Units

CT Associated with a Pseudo-Unit

If the CT is coming offline during the period where the associated PSU has a DAM schedule:

$$RT\_RDSA_k^c = Max\left(0, \sum^T \left[(-1) \times OP\left(DAM\_LMP_h^c, AQEI_{k,h}^{c,t}, BE_{k,h}^{c,t}\right) + Max\left(0, (-1) \times OP\left(DAM\_LMP_h^c, AQEI_{k,h}^{c,t}, DAM\_BE_{k,h}^c\right)\right)\right]\right)$$

Otherwise:

$$RT\_RDSA_k^c = Max\left(0, \sum^T \left[(-1) \times OP\left(RT\_LMP_h^{c,t}, AQEI_{k,h}^{c,t}, BE_{k,h}^{c,t}\right)\right]\right)$$

Where:

‘T’ is the set of all *settlement* intervals ‘t’ beginning from the first interval that the *facility* is scheduled below MLP to come offline and ends when there is no dispatch or a zero MWh *dispatch instruction*.

‘$\mathrm{BE}_{k,h}^{c,t}$’ as defined in Section 3.5.6 Table 3-33.

In this instance, $\mathrm{BE}_{k,h}^{c,t}$ is a matrix of ‘n’ *price-quantity pairs*, equivalent to the matrix $\mathrm{BE}_{k,h}^{p,t}$ only with each *price* multiplied by a ramp-down factor (RDF) and each *quantity* multiplied by $\left(1 - \mathrm{ST\_Portion}_{k,d1}^{p}\right)$.

Where:

$\mathrm{BE}_{k,h}^{p,t}$ is a matrix of ‘n’ *price-quantity pairs offered* by *market participant* ‘k’ to supply *energy* at *pseudo-unit* ‘p’ associated with CT *delivery point* ‘c’ during the *settlement hour* ‘h’ immediately before the hour in which ramp-down begins.

‘$\mathrm{DAM\_BE}_{k,h}^{c}$’ as defined in Section 3.5.4 Table 3-15.

In this instance, $\mathrm{DAM\_BE}_{k,h}^{c}$ is a matrix of ‘n’ *price-quantity pairs*, equivalent to the matrix $\mathrm{DAM\_BE}_{k,h}^{p}$ only with each *quantity* multiplied by $\left(1 - \mathrm{ST\_Portion}_{k,d1}^{p}\right)$.

ST Associated with a Pseudo-Unit

The RT_RDSA will be calculated for an ST associated with a PSU if and only if the ST is actually ramping down from its 1x1 *minimum loading point* to come offline. No such calculation will be performed for PSU ramp-downs that do not result in the ST coming offline.

If there is only one associated CT online prior to and during the ramp-down of the ST, the ST RT_RDSA calculation will rely upon the *offers* for the PSU associated with that CT. If there are multiple CTs ramping down simultaneously during the ST’s ramp-down, the ST RDSA calculation will rely upon the *offers* for whichever PSU’s associated CT was the last to drop below its CT MLP. That PSU will henceforth be referred to as the ramp-down PSU.

If the ST is coming offline during a period where the ramp-down PSU has a DAM schedule:

$$RT\_RDSA_k^s = Max\left(0, \sum^T \left[(-1) \times OP\left(DA\_LMP_h^s, AQEI_{k,h}^{s,t}, BE_{k,h}^{s,t}\right) + Max\left(0, (-1) \times OP\left(DA\_LMP_h^s, AQEI_{k,h}^{s,t}, DAM\_BE_{k,h}^s\right)\right)\right]\right)$$

Otherwise:

$$RT\_RDSA_k^s = Max\left(0, \sum^T \left[(-1) \times OP\left(RT\_LMP_h^{s,t}, AQEI_{k,h}^{s,t}, BE_{k,h}^{s,t}\right)\right]\right)$$

Where:

‘T’ is the set of all *settlement* intervals ‘t’ beginning from the first interval that the ST *facility* is scheduled below its 1x1 MLP to come offline and ends when there is no *dispatch* or a zero MWh *dispatch instruction*.

'$\mathrm{BE}^{\mathrm{s,t}}_{\mathrm{k,h}}$'	as defined in Section 3.5.6 Table 3-33. In this instance, $\mathrm{BE}^{\mathrm{s,t}}_{\mathrm{k,h}}$ is a matrix of 'n' *price-quantity pairs*, equivalent to the matrix $\mathrm{BE}^{\mathrm{p,t}}_{\mathrm{k,h}}$ only with each *price* multiplied by a ramp-down factor (RDF) and each *quantity* multiplied by $\mathrm{ST\_Portion}^{\mathrm{p}}_{\mathrm{k,d1}}$. Where: $\mathrm{BE}^{\mathrm{p,t}}_{\mathrm{k,h}}$ is a matrix of 'n' *price-quantity pairs offered* by *market participant* 'k' to supply *energy* at *pseudo-unit* 'p' associated with ST *delivery point* 's' during the *settlement hour* 'h' immediately before the hour in which ramp-down begins.
'$\mathrm{DAM\_BE}^{\mathrm{s}}_{\mathrm{k,h}}$'	as defined in Section 3.5.4 Table 3-15. In this instance, $\mathrm{DAM\_BE}^{\mathrm{s}}_{\mathrm{k,h}}$ is a matrix of 'n' *price-quantity pairs*, equivalent to the matrix $\mathrm{DAM\_BE}^{\mathrm{p}}_{\mathrm{k,h}}$ only with each *quantity* multiplied by $\mathrm{ST\_Portion}^{\mathrm{p}}_{\mathrm{k,d1}}$.

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

The real-time ramp-down *settlement amount* uplift (RT_RDSAU) is intended to recover the cost of the RT_RDSA *settlement amounts* accrued in the *real-time market*.

The RT_RDSA Uplift is allocated on a pro-rata basis to all *real-time market* loads and exports on a daily basis.

The formulation of the RT_RDSA Uplift is as follows:

$$RT\_RDSAU_k = \sum_K^{M,T} RT\_RDSA_k^m \times \left[\sum^{M,T}(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}) \,/\, \sum_K^{M,T}\left(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}\right)\right]$$

Where:

'M'	is the set of all *delivery points* 'm' and *intertie metering points* 'i'.
'T'	is the set of all *metering intervals* 't' in *settlement hour* 'h'.
'K'	is the set of all *market participants* 'k'.

3.7.16.10 Replacement Energy Offer Program

Market participants will continue to be able to use the Replacement Energy Offers Program (REOP) to revise the *offer* of one of their *generation units* in response to a *forced outage* or forced de-rate of another of their *generation units*.

For non-quick start *generation facilities*, the replacement unit will not be required to meet the eligibility requirements of the original unit in the future market. The *IESO* will not transfer the PD commitment to the replacement unit. The *pre-dispatch scheduling* process will evaluate start-up offers, speed no-load offers and *energy offers* to economically schedule these resources, based on the revised *dispatch data* submitted during the mandatory window.

Refer to the Grid and Market Operations Integration detailed design document for more information on replacement *offers*.

Settlement – Current Hour

In the current hour, *IESO* operators will *dispatch* up the replacement unit to provide the correct inputs for the RT calculation engine until the replacement *offers* take effect. During this time, the replacement unit will be ineligible for a make-whole payment for the MWs that is dispatched up.

Eligibility for real-time make-whole payment for the forced unit will be limited up to the interval prior to the *forced outage*. The forced unit will also be subject to a balancing charge for undelivered DA scheduled injections under the two-*settlement* system for failure to meet its DAM schedule.

An NQS *generation unit* that fails to complete its PD commitment due to a *forced outage* (or forced de-rate) may trigger a generator failure charge for its failure to deliver *energy*. It may still be eligible for the generator offer guarantee. Both *settlement amounts* will be assessed and calculated per their respective eligibility rules.

Settlement – Future Hours

For future hours, eligibility for make-whole payment and generator offer guarantee will be determined by the replacement unit meeting its binding schedule and per the eligibility rules discussed in the respective sections of this detailed design document. The GFC may also apply should the NQS *generation facility* fail to deliver *energy* as committed by the PD calculation engine.

3.8 Market Remediation

Following a market failure event, the *IESO* will assess market impacts. The *IESO* will also continue to 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. Published results may also be deemed invalid due to a number of factors, and corrective actions may be required after-the-fact.

3.8.1.1 Day-Ahead Market Remediation

The day-ahead market will produce prices, financially binding schedules and commitments that reflect expected operations for a particular *dispatch day*.

In the unlikely event that a DAM error is identified after the results have been posted, the *IESO* will have the option to declare a *dispatch scheduling error* (DSE). Today, this option is only available in the *real-time market*. The *IESO* will not retroactively correct DAM prices and schedules.

In the unlikely event that a DAM failure occurs and the DAM cannot be completed and validated by prescribed timelines, the *IESO* will declare a DAM failure, similar to today when the *IESO* has declared a DACP failure. To ensure *reliability* of the *IESO-controlled grid,* the *IESO* may manually commit resources, including NQS resources, prior to the first run of the pre-dispatch calculation engine. All *intertie* schedules will be determined through the PD scheduling process. For more information on this process, refer to the Grid and Market Operations Integration detailed design document.

Settlement Impact – DAM Error

The *IESO* will not retroactively correct DAM prices and schedules. The incorrect input data will be received by the *settlement process* and *settlement amounts* calculated using this data. A *dispatch scheduling error* may be declared and after-the-fact *settlement* corrections will be required to any transaction(s) that were a direct result of that error. The *settlement process* will be provided with the *dispatch day, dispatch hour* and impacted transaction(s).

Settlement Impact – DAM Failure

When the *IESO* declares a DAM failure, no financially binding schedules or prices will be created or posted, and no operational commitments will be generated based on DAM outcomes. Operational outcomes for the *dispatch day* will be settled solely based on *real-time market* dispatch and pricing. As a result, there will be no *settlement* of the DAM, similar to today when a DACP failure is declared.

3.8.1.2 Pre-Dispatch Remediation

The PD scheduling process determines the commitments required for the real-time scheduling and dispatch process. Pre-dispatch data is used to issue NQS binding start-up notifications, apply commitment constraints and produce advisory schedules and prices for all participating resources. In the hour prior to the *dispatch hour*, PD determines the hourly *intertie* transaction schedules.

In the event that a PD error or calculation engine failure occurs, no corrections to *pre-dispatch schedules* or prices will be made. Deviations from the last recorded and published PD calculation engine run will be reflected in real-time inputs. This is a continuation of the process in the current market. For more information on this process, refer to the Grid and Market Operations Integration detailed design document.

Settlement Impact – PD Error

NQS resources and *intertie* transactions committed in pre-dispatch will be adjusted for in real-time when a PD error occurs. Any deviations from pre-dispatch will be reflected in real-time inputs through transaction codes and communicated to the *settlement process.* This is a continuation of today’s process.

Settlement Impact – PD Failure

NQS resources and *intertie* transactions committed in pre-dispatch will be adjusted for in real-time when a PD failure occurs. Any deviations from pre-dispatch will be reflected in real-time inputs through transaction codes and communicated to the *settlement process.* This is a continuation of today’s process.

3.8.1.3 Real-Time Market Remediation

Real-time calculation engine failures can occur and errors may result. When an RTM failure occurs, the calculation engine does not calculate updated 5-minute *dispatches* and prices that would otherwise reflect the most recent conditions and market inputs. The current market processes for *real-time market* remediation and applying corrective actions will continue in the future market when missing and/or incorrect prices and schedules are identified.

In the event that a *real-time market* error is identified after the results have been posted, the *IESO* will have the option to declare a *dispatch scheduling error* (DSE). This is a continuation of the current market. The *IESO* will not retroactively correct RTM prices and schedules.

In event that a *real-time market* failure occurs, the *IESO* will settle using *administrative prices*, consistent with today. In the future market, under a single schedule market, the corresponding schedule will not be corrected when prices are administered. Today, the *IESO* administers both the price and corresponding *market schedule* (unconstrained schedule). For more information on this process, refer to the Grid and Market Operations Integration detailed design document.

Settlement Impact – RTM Error

For pricing corrections outside of the available timeframe, the *IESO* will not retroactively correct RTM prices and schedules. The incorrect input data will be received by the *settlement process* and *settlement amounts* calculated using this data. The *IESO* has the option to declare a *dispatch scheduling error* and after-the-fact *settlement* corrections will be required to any transactions(s) that were a direct result of that error. The *settlement process* will be provided with the *dispatch day, dispatch hour* and impacted transaction(s).

Any schedule corrections for *intertie* transactions or verbal dispatches will be made within the available timeframe and assigned appropriate coding to align with what transpired in real-time. The corresponding price will not be corrected. This will be provided to the *settlement process*.

Settlement Impact – RTM Failure

In the event of a *real-time market* failure resulting in incorrect or missing prices, the *IESO* will administer prices within the available timeframe for price correction. The schedules associated with the price correction will not be corrected. *Market participants* will be settled using the administered real-time price. The *settlement process* will receive the *administered price(s). Administrative pricing* is discussed in detail in the following section.

Refer to the Grid and Market Operations Integration detailed design document for other *IESO* market remediation actions, in each of market timeframes, from day-ahead market through to real-time market.

3.8.1.4 Administrative Pricing

The *dispatch algorithm* calculates *energy* and *operating reserve market prices*, which are normally published within five minutes of each 5-minute interval within a *dispatch interval*. At times, this mechanism does not function normally due to failures or *planned outages* of market systems, incorrect inputs to the *dispatch algorithm* or market suspension. In such cases, a market remediation method that the *IESO* can apply is to establish *administrative prices* for the affected *dispatch intervals.*

Today, the *IESO* uses set price administration rules to resolve any incorrect or missing prices in the *real-time market*. In the future, *administrative pricing* will continue to be an available option as an after-the-fact correction process in the *real-time market* only. The *IESO* will continue to assess pricing and scheduling errors to determine the appropriate *administrative pricing* method to apply.

In the current market, *market prices* and the corresponding *market schedules* for those affected *dispatch intervals* are administered. In the future single schedule market, only the *real-time market price* will be administered.

Administrative pricing will ensure *market participants* are not disadvantaged when there is a system failure in the *real-time market*. Today, *market participants* may request additional compensation due to an *administrative pricing* event as a result of negative CMSC or insufficient compensation for *energy*. In the future, requests for additional compensation will not be required. The real-time make-whole payment will ensure that *market participants* are made whole to their costs – the real-time make-whole payment to *market participants* will always be compensatory in nature. The *settlement process* will be informed when an *administrative pricing* event occurs and will receive the administered prices as all *settlement* calculations with a real-time locational marginal price will be impacted.

The current market allows pricing corrections to be made within two *business days* after the affected operating day. In the future market, a change to allow pricing corrections to be made within four *business days* after the affected operating day is required as the number of prices and data associated with those prices significantly increases with the introduction of location marginal pricing (LMP).

Refer to the Grid and Market Operations Integration detailed design document for further information.

3.9 Financial Neutrality

3.9.1 General Principles of Financial Neutrality

The general principles of financial neutrality for transactions other than transactions in the *TR market*, are set out in Chapter 9, Section 6.16 of the *market rules*. Controls within the *settlement* process will perform the financial balance of the calculated charges and payments by using the following principles:

- for *hourly market* transactions: sum of all payments for all *market creditors* will equal the sum of all charges for *market debtors* involved in *hourly market* transactions, for each *trading day* of a *billing period.*
- for all other transactions: for monthly charges, adjustment charges and payments, the sum of all payments to *market creditors* of those transactions will equal the sum of all charges to *market debtors* of those transactions for each *billing period.*

The above principles will continue for the future *real-time market* and will apply to the day-ahead market also.

3.9.2 Neutrality

The combined first and second *settlement amounts* of the two-*settlement* system will result in a financially balanced market. There are eight major groupings of *settlement amounts*, seven of which relate to the physical market and form a neutral basis for invoicing *market participants* on a monthly basis. The physical market will be financially balanced (net neutral) each month. There is one major grouping of *settlements amounts* for the financial *TR market* and is discussed in Section 3.9.3: Neutrality – DAM TR Auction Process.

Figure 3-1 illustrates the major balancing groups.

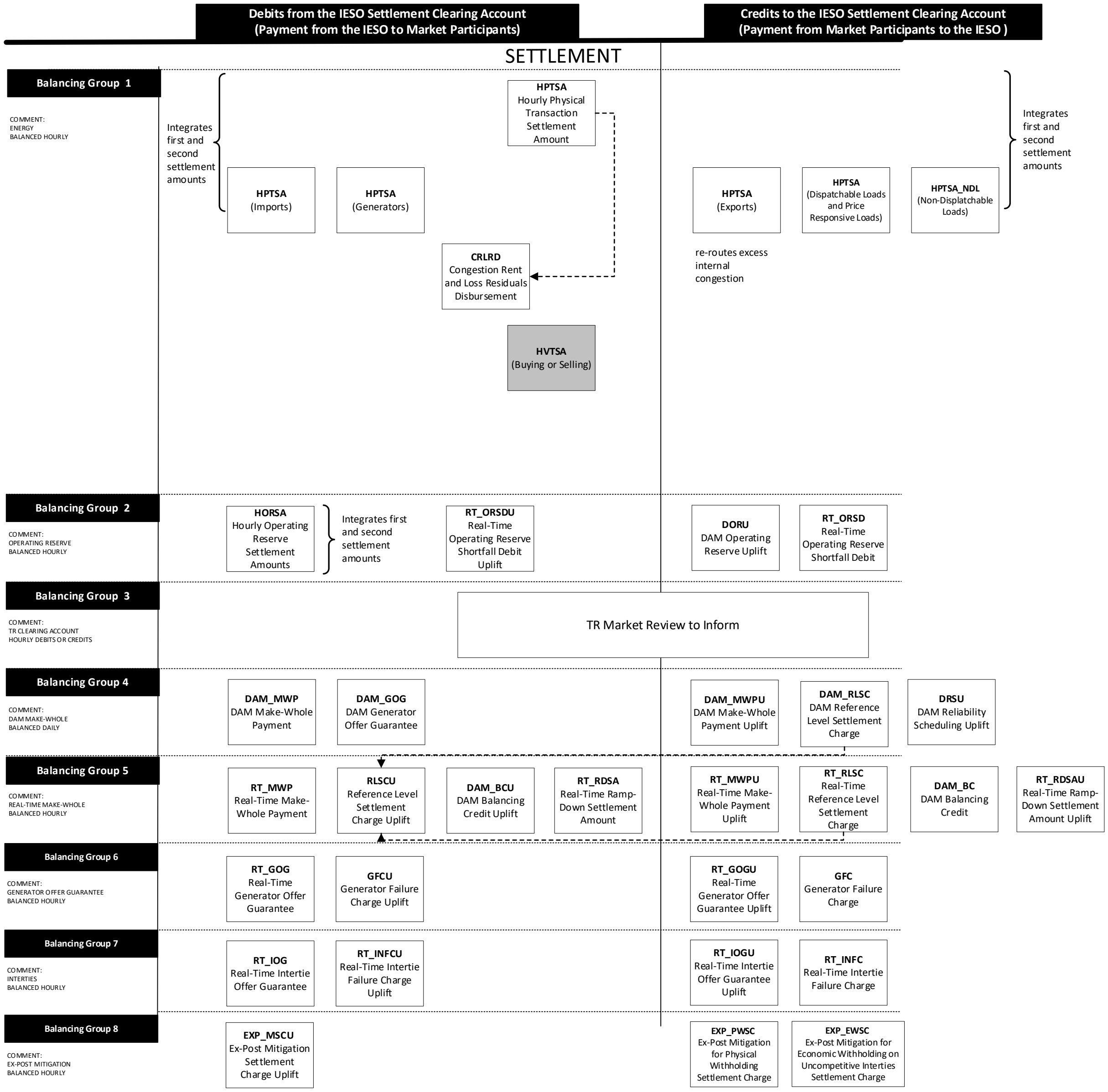

Figure 3-1: Settlement Amount Balancing Groupings

3.9.3 Neutrality - DAM TR Auction Process

As per existing practices regarding the auction of *TRs*, DAM *TR auctions* will be settled as part of the weekly *settlement* invoicing and payments cycle.

When looking at the *settlement* data for *TR auctions* in isolation, the associated *settlement amounts* will represent amounts owing to the *IESO* from *market participants* for the sale of DAM *TR*. These amounts will be held in the *TR clearing account*.

Changes proposed through MRP will have an impact on the financial *TR market*. Upon completion of the TR Market Review, *settlement amounts* will be determined for the future *TR market*. Refer to Section 3.7.15: Transmission Rights.

It is important to note that the financial *TR market* is self-funding and cannot be financially balanced each month. This is consistent with the operation of the *TR clearing account* in today's market.

This grouping of *settlement amounts* corresponds to "Balancing Group 3" illustrated in Figure 3-1.

3.10 Regulatory Processes

The regulatory process involves the determining, collecting and remitting of applicable regulated *settlement amounts* in compliance with relevant provisions of the *applicable laws*. The *applicable laws*, include without limitation, the *Electricity Act, 1998,* the *Ontario Energy Board Act, 1998,* and any regulations enacted thereunder with respect to *settlement*.

The *IESO*, in collaboration with the appropriate regulatory bodies will review relevant legislation and regulation to identify what amendments may be required as a result of MRP. The *settlement process* will directly incorporate any amendments into the *settlement* calculations.

3.11 Settlement Reports

3.11.1 Settlement Statements and Data Files

As part of the *settlement process*, *settlement statements* are issued to each *market participant* to cover each *trading day*. Separate *preliminary settlement statements* and *final settlement statements* are issued to cover:

- *physical market* transactions in the *real-time market* and *TR market* (excluding *TR auctions*); and
- financial market transactions in all rounds of any *TR auction.*

For each *settlement statement* issued in the *physical market,* accompanying data files are also issued to *market participants* in order to reconcile their *settlement statements* in an accurate and timely manner. There are no data files in the financial market.

All *settlement statements* and data files will continue to be available on the *IESO* Reports Site in the same format in the future market. Existing data files will be reviewed for relevancy in the future market and updated accordingly.

With the introduction of the day-ahead market, existing *settlement statements* and supporting data files will be updated to integrate new *settlement amounts.* In some instances, new supporting data files may be required to support the *real-time market* and day-ahead market activities. Applicable data will continue to be provided in accordance with information confidentiality guidelines.

3.11.2 Private and Public Reports

The *IESO*'s current reports produced by the *settlement process* will be impacted by MRP. Reports will continue to be provided in accordance with information confidentiality guidelines.

Refer to the Publishing and Reporting Market Information detailed design document for a list of non-*settlement process* reports *published* by the *IESO*. The *settlement process* will continue to contribute to other reports *published* by the *IESO*, by providing the applicable *settlement data*.

Current Reports

The *settlement process* produces several reports and *publishes* several *settlement* values that are made available to *market participants*. Modifications will be required as a result of changes to *energy* pricing and *settlement amounts*, which can include new, amended, replaced or disposed amounts.

Given the nature of the data, reports will continue to be available as either:

- a public report that is available to all *market participants* on the *IESO* website; or
- a private report that is confidential and specific to a *market participant*.

Table 3-70 lists reports that are produced by the *settlement process* and will require some modification.

Table 3-70: Reports Produced by the Settlement Process

Report Name	Report Audience	Impact
IOG Settlements Detail Report	Private	Revise
Condense and Speed no Load Events Report	Private	No Changes
Hourly Uplift Charges, 2002-20YY	Public	Revise
Hourly Uplift Charges, year-to-date	Public	Revise
Daily Uplift, 2011-present	Public	Revise
Monthly Uplift, 2002-20YY	Public	Revise
Monthly Uplift, year-to-date	Public	Revise
Hourly and Monthly Charges	Public	Revise
Intertie Offer Guarantee Charges, 2002-20YY	Public	Revise
Intertie Offer Guarantee Charges, year-to-date	Public	Revise
Generator Output by Fuel Type Monthly Report	Public	No Changes
IESO Global Adjustment Class B Rates	Public	No Changes
Peak System Demand Data Report (Preliminary and Final)	Public	No Changes
List of Resources for Physical Bilateral Contracts	Public	Revise
Default Levy Report	Private	No Changes

In addition to these reports, the *settlement process* will continue to *publish* the following *settlement* schedule and payments calendars *(SSPC)* to the *IESO* website with the exception of the Real-Time Generation Cost Guarantee (RT-GCG) Payment Calendar, which will become obsolete under MRP.

Table 3-71: Calendars Produced by the Settlement Process

Report Name	Report Audience	Impact
Physical Market Settlement Schedule and Payments Calendar	Public	No Changes
Financial Market Settlement Schedule and Payments Calendar	Public	No Changes
Physical / Financial Market Holiday Schedule	Public	No Changes
Real-time Generation Cost Guarantee Payment Calendar	Public	Obsolete

Further, the *settlement process* will continue to *publish* the *settlement* values as listed in Table 3-72 to the *IESO* website. Any amendments that may be required to the methodology to calculate each of these values as a result of MRP will be reviewed with the appropriate regulatory body.

Table 3-72: Settlement Values

Report Name	Report Audience	Impact
Global Adjustment – Class B GA Estimate & Actual Rates	Public	No Changes
Global Adjustment and Peak Demand Factor	Public	No Changes
Global Adjustment Components and Costs	Public	No Changes
Peak Demand Factor and Capacity Based Recovery Amount for Class A	Public	No Changes

New Reports

New reports are not anticipated. Rather, new *settlement amounts* will be integrated into the existing *settlement statements* and data files. In some instances, new supporting data files may be required to support the *real-time market* and day-ahead market activities.

3.12 Notice of Disagreement and Notice of Dispute

3.12.1 Notice of Disagreement

As described earlier, all DAM *settlement amounts*, including the *settlement amounts* resulting from the first and second *settlement* under the two-*settlement* system, will be included on a *preliminary settlement statement* and integrated into the existing *Notice of Disagreement* (NoD) process. *Market participants* will continue to submit a NoD for a *settlement amount* reported on the *preliminary settlement statement* if the *market participant* believes the amount to be incorrect and that the error relates to the:

- application of a *settlement* formula; or
- usage of *settlement* data received by the *settlement process* as per the *market rules.*

A NoD may not be submitted regarding the calculation of:

- the locational marginal price of *energy* or any class of *operating reserve* for any *dispatch interval* in a given *settlement hour*;
- the Ontario zonal price of *energy* for any *dispatch interval* in a given *settlement hour;* or
- the equations used to calculate the charges.

The content of the NoD will continue to meet the information requirements set out by Chapter 9, Section 6.6 of the *market rules.*

3.12.2 Notice of Dispute

If a *market participant* does not agree with the *notice of disagreement* decision, they may raise a *notice of dispute* through the Dispute Resolution process.

The content of the dispute will continue to meet the information requirements set out by Chapter 3, Section 2.5 of the *market rules.*

3.12.3 Timelines

There will be no changes to the current NoD and dispute timelines as a result of MRP. Under an amended *market rules* framework, which will be carried out separately from MRP, the *IESO* will review options and the feasibility to change the current NoD and dispute timelines, which would integrate *market participant* disagreements beyond the issuance of the *final settlement statement* into the *Notice of Disagreement* process.

3.12.3.1 Physical Markets

All NoDs with respect to *physical market settlement amounts* must be registered with the *IESO* within four *business days* of receipt of a *preliminary settlement statement*, which is issued 10 *business days* after the *physical market trading day.* A *notice of dispute* must be submitted within 20 *business days* after the *final settlement statement* has been issued for the *trading day* to which the dispute pertains.

The *IESO* will make all reasonable attempts to resolve a NoD in time for the issuance of the *final settlement statement* for the affected *trading day*. However, the *IESO* will continue to have additional time up to 15 *business days* after the issuance of the *final settlement statement* if required – as allowed under the current *market rules*.

3.12.3.2 Financial Market

All NoDs with respect to the financial market *settlement amounts* must be registered with the *IESO* within two *business days* of receipt of a *preliminary settlement statement*, which is issued two *business days* after the close of a *transmission rights auction.* Disputes must be raised within 20 *business days* after the *final settlement statement* has been issued.

3.13 Market Power Mitigation

The Market Power Mitigation process developed for the future *market* will have a direct impact on the day-to-day *settlement process* and the assessment of market power mitigation after final *settlement*. The new framework for market power mitigation will consist of the following processes:

- Ex-ante validation of non-financial *dispatch data*;
- Ex-ante mitigation for economic withholding affecting *energy* and *operating reserve* prices;
- *Settlement* mitigation of make-whole payments;
- Ex-post mitigation for physical withholding *energy* and *operating reserve* prices; and
- Ex-post mitigation for economic withholding affecting prices or make-whole payments on uncompetitive *interties*.

Ex-ante validation of select non-financial *dispatch data* parameters will be performed at the time of *dispatch data* submission. The *IESO* will evaluate whether the non-financial *dispatch data* parameters values exceed each parameter's reference level plus a predefined conduct threshold. If any one of the submitted non-financial *dispatch data* parameter values is outside the acceptable range determined by the respective reference level value and conduct threshold, the non-financial *dispatch data* will be rejected. Non-financial *dispatch data* submissions that pass ex-ante validation will be used by the *settlement process* and are identified in Section 3.5.3 of this document. Ex-ante validation of non-financial *dispatch data* is also described in Section 3.5 of the Market Power Mitigation detailed design document.

Ex-ante mitigation for economic withholding will be performed by the ex-ante mitigation functions of the DAM, PD and RT calculation engines. The *settlement process* will use prices and schedules produced by the calculation engines including *market prices* that may be the result of ex-ante price mitigation for the *settlement* of *energy* and *operating reserve* in the day-ahead market and *real-time market*.

Settlement mitigation of make-whole payments will use mitigated *dispatch data* when such data results from the failure of conduct tests performed by the mitigation functions of the DAM, PD and RT calculation engines. *Settlement* mitigation of make-whole payments will involve the following activities:

- *Settlement* mitigation of make-whole payments will be performed as part of the day-to-day *settlement process* before the production of *preliminary settlement statements* and is described in Section 3.7.13 below and in Section 3.8 of the Market Power Mitigation detailed design;
- *Settlement* mitigation of make-whole payments will also be applied to *dispatch data* received for NQS *generation units* that receive operational commitments in the day-ahead market or pre-dispatch operational commitments for hours during which system conditions present no constraints that would trigger ex-ante conduct tests; and
- *Settlement* mitigation of make-whole payments will also be applied to dual-fuel resources for which reference level value changes to reflect the cost of a higher cost fuel are requested by a *market participant*. *Market participants* can submit their requests for reference value changes prior to the close of the bidding window for the day-ahead market or prior to the close of the mandatory window in the *real-time market*. The *settlement process* for mitigating duel-fuel resources will be performed before the production of *preliminary settlement statements* and is described in Section 3.13.2 below and in Section 3.12 of the Market Power Mitigation detailed design.

The new mitigation framework introduces a conduct and impact testing methodology. For resources that fail ex-ante conduct tests, the *IESO* will replace each failed *dispatch data* parameter value with the respective pre-established reference level value.

The schedules and prices resulting from the application of ex-ante conduct and price impact mitigation tests will be directly incorporated into the calculations of *settlement amounts* for *energy* and *operating reserve*. Resources for which *dispatch data* has failed the ex-ante conduct tests, or NQS *generation units* receiving an operation commitment, the *settlement process* will apply make-whole payment impact tests using reference level values used by, or available to, the calculation engines whether or not system conditions triggered ex-ante conduct and impact testing.

The Market Power Mitigation process will apply an ex-post approach to mitigate the exercise of market power that cannot be addressed by ex-ante mitigation actions. Such ex-post mitigation activities may result in *settlement* charges and will include:

- Ex-post mitigation for physical withholding in the *energy* and *operating reserve markets*; and
- Ex-post mitigation for economic withholding on uncompetitive *interties*.

The *settlement process* will continue to support these mitigation activities performed after final *settlement* for any *trading day*. These ex-post market power mitigation activities are described in the Market Power Mitigation detailed design Section 3.9 and Section 3.10.

3.13.1 Make-Whole Payment Impact Test

When a resource meets the conditions to carry out a make-whole payment mitigation impact test, the *IESO* will determine what the *settlement amount* would have been, if the *dispatch data* had been subject to mitigation based on the set of conduct and impact thresholds that apply to the most restrictive constrained area. The most restrictive set of thresholds for the *dispatch data* will be determined over the period that the *settlement amount* is calculated. Therefore, if the *settlement amount* is calculated over multiple hours, the hour with the most restrictive set of thresholds will determine the set of thresholds used in all hours of the calculation. Consider an example where a *settlement amount* is calculated over four hours, where one hour is using a set of thresholds related to *reliability* constraints, and the other hours are using a BCA set of thresholds. In this case, the set of thresholds for *reliability* constraints are more restrictive of the two sets of thresholds. Therefore, the *reliability* thresholds will be used in all hours for the make-whole payment impact test. The *dispatch data* will be mitigated using the most restrictive set of conduct and impact thresholds and will be called enhanced mitigated for conduct *dispatch data*.

Similarly, when a *pseudo-unit's dispatch data* meets the conditions for a make-whole payment test, the *IESO* will use the most restrictive set of conduct and impact thresholds that apply. As a result, translation of the pseudo unit *offers* will be based on the most restrictive thresholds in order to derive the mitigated physical unit *offers*.

Based on the most restrictive set of conduct and impact thresholds that apply in the calculation period of the *settlement amount*, there will be specific thresholds used in the comparison test. The thresholds can be found in the following tables within Section 3.8 of the Market Power Mitigation detailed design document:

- Table 3-16: Make-Whole Impact Thresholds for NCAs and DCAs
- Table 3-18: Make-Whole Payment Impact Thresholds for BCAs
- Table 3-20: Make-Whole Payment Impact Thresholds for Reliability Constraints
- Table 3-22: Make-Whole Payment Impact Thresholds for Global Market Power - Energy
- Table 3-24: Make-Whole Payment Impact Thresholds for Local Market Power – Operating Reserve
- Table 3-26: Make-Whole Payment Impact Thresholds for Global Market Power – Operating Reserve

The *settlement amounts* subject to the make-whole payment impact test are:

- DAM_MWP;
- DAM_GOG;
- RT_MWP;
- RT_GOG;
- DAM_BC; and
- RDSA.

Energy Market Conditions

The *IESO* will perform the make-whole payment impact test for any resource that meets any of the following conditions:

- A resource met the conditions for ex-ante mitigation for price impact for global market power in the BCA, in an NCA, or in a DCA; or
- A resource is scheduled as a result of a *reliability* constraint; or
- A resource that received a RT_GOG or a DAM_GOG has a positive congestion component greater than $0/MWh on any binding constraint; or
- A resource that received a RT_GOG or a DAM_GOG has a positive congestion component greater than $0/MWh on an active constraint that would have been binding or violated but for the commitment of the resource.

Operating Reserve Market Conditions

The *IESO* will perform the make-whole payment impact test for any resource that meets any of the following conditions:

- The resource was tested for local market power for *operating reserve* price impact or for global market power for *operating reserve* price impact, is scheduled to provide *operating reserve* and is receiving a make-whole payment; or
- The resource received a RT_GOG or DAM_GOG, was scheduled to provide *operating reserve*, and would otherwise receive an unmitigated make-whole payment for that commitment that exceeds $10,000.

3.13.1.2 DAM Make-Whole Payment (DAM_MWP)

The make-whole payment impact test will compare:

1. the DAM_MWP based on *energy* and *operating reserve* schedules and prices produced by the calculation engine and mitigated for impact *dispatch data* submitted to the DAM for *energy* and *operating reserve*; and
2. the DAM_MWP based on *energy* and *operating reserve* schedules and prices produced by the calculation engine and enhanced mitigated for conduct *dispatch data* for *energy* and *operating reserve*.

If the first DAM_MWP is greater than the second DAM_MWP by more than the make-whole payment impact threshold, then the resource fails the make-whole payment impact test. If the resource fails the make-whole payment impact test, the *market participant* will be paid the DAM_MWP based on the enhanced mitigated for conduct *dispatch data* for *energy* and *operating reserve*. Otherwise, the DAM_MWP will be based on the mitigated for impact *dispatch data* as used by the calculation engine.

3.13.1.3 DAM Generator Offer Guarantee (DAM_GOG)

In the ex-ante time frame, an individual hour of the DAM commitment may be mitigated, but other hours may not. When the make-whole payment impact test is triggered, the DAM_GOG needs to be calculated based on make-whole payment impact test thresholds for the DAM_GOG calculation period.

The make-whole payment impact test will compare:

1. the DAM_GOG based on *energy* and *operating reserve* schedules and prices produced by the calculation engine and mitigated for impact *dispatch data* submitted to the DAM for *energy* and *operating reserve*; and
2. the DAM_GOG based on *energy* and *operating reserve* schedules and prices produced by the calculation engine and enhanced mitigated for conduct *dispatch data* for *energy* and *operating reserve*.

If the first DAM_GOG is greater than the second DAM_GOG by more than the make-whole payment impact threshold, then the resource has failed the make-whole payment impact test. If the resource fails the make-whole payment impact test, the *market participant* will be paid the DAM_GOG based on the enhanced mitigated for conduct *dispatch data* for *energy* and *operating reserve*. Otherwise, the DAM_GOG will be based on the mitigated for impact *dispatch data* as used by the calculation engine.

3.13.1.4 RT Make-Whole Payment (RT_MWP)

The make-whole payment impact test will compare:

1. the RT_MWP based on *energy* and *operating reserve* schedules and prices produced by the calculation engine and mitigated for impact *dispatch data* submitted to the RT calculation engine for *energy* and *operating reserve*; and
2. the RT_MWP based on *energy* and *operating reserve* schedules and prices produced by the calculation engine and enhanced mitigated for conduct *dispatch data* for *energy* and *operating reserve*.

If the first RT_MWP is greater than the second RT_MWP by more than the make-whole payment impact threshold, then the resource has failed the make-whole payment impact test. If the resource fails the make-whole payment impact test, the *market participant* will be paid the RT_MWP based on the enhanced mitigated for conduct *dispatch data* for *energy* and *operating reserve*. Otherwise, the RT_MWP will be based on the mitigated for impact *dispatch data* as used by the calculation engine.

3.13.1.5 RT Generator Offer Guarantee (RT_GOG)

In the ex-ante time frame, an individual hour of the RT commitment might be mitigated, but other hours might not.

The make-whole payment impact test will compare:

1. the RT_GOG based on *energy* and *operating reserve* schedules and prices produced by the calculation engine and mitigated for impact *dispatch data* submitted to the RT calculation engine for *energy* and *operating reserve*; and
2. the RT_GOG based on *energy* and *operating reserve* schedules and prices produced by the calculation engine and enhanced mitigated for conduct *dispatch data* for *energy* and *operating reserve*.

If the first RT_GOG is greater than the second RT_GOG by more than the MWP impact threshold, then the resource has failed the make-whole payment impact test. If the resource fails the make-whole payment impact test, the *market participant* will be paid the RT_GOG based on the enhanced mitigated for conduct *dispatch data* for *energy* and *operating reserve*. Otherwise, the RT_GOG will be based on the mitigated for impact *dispatch data* as used by the calculation engine.

3.13.1.6 DAM Balancing Credit (DAM_BC)

The DAM_BC is only necessary when the *IESO* dispatches down a resource in RT for *reliability*. This means that the most limiting reference threshold used in the calculation period of this *settlement* charge will always be the *reliability* reference thresholds for the *dispatch data*.

The make-whole payment impact test will compare:

1. the DAM_BC based on *energy* and *operating reserve* schedules and prices produced by the calculation engine and the mitigated for impact *dispatch data* submitted to the RT for *energy* and *operating reserve*; and
2. the DAM_BC based on *energy* and *operating reserve* schedules and prices produced by the calculation engine and enhanced mitigated for conduct *dispatch data* for *energy* and *operating reserve* using the *reliability* thresholds.

If the first DAM_BC is greater than the second DAM_BC by more than the make-whole payment impact threshold, then the resource has failed the make-whole payment impact test. If the resource fails the make-whole payment impact test, the *market participant* will be paid the DAM_BC based on the enhanced mitigated for conduct *dispatch data* for *energy* and *operating reserve* using the *reliability* threshold. Otherwise, the DAM_BC will be based on the mitigated for impact *dispatch data* as used by the calculation engine.

3.13.1.7 Real-Time Ramp Down Settlement Amount (RT_RDSA)

Unlike the other charges discussed in this section, the *offers* used in the calculation of the RT_RDSA is always the *offer* from the hour prior to the beginning of the ramp down period. Therefore, the most restrictive set of thresholds for the *dispatch data* will be determined in the hour prior to the ramp down period.

The make-whole payment impact test will compare:

1. the RT_RDSA based on *energy* and *operating reserve* schedules and prices produced by the calculation engine and mitigated for impact *dispatch data* submitted to the RT for *energy* and *operating reserve* in the hour prior to the ramp down period; and
2. the RT_RDSA based on *energy* and *operating reserve* schedules and prices produced by the calculation engine and enhanced mitigated for conduct *dispatch data* for *energy* and *operating reserve* from the hour prior to the ramp down period.

If the first RT_RDSA is greater than the second RT_RDSA by more than the make-whole payment impact threshold, then the resource has failed the make-whole payment impact test. If the resource fails the make-whole payment impact test, the *market participant* will be paid the RT_RDSA based on the enhanced mitigated for conduct *dispatch data* for *energy* and *operating reserve*. Otherwise, the RDSA will be based on the mitigated for impact *dispatch data* as used by the calculation engine.

3.13.2 Reference Level Settlement Charges (RLSC)

The reference level *settlement* charges (RLSC) are *settlement* amounts that apply to dual-fuel resources where the resource can use two types of fuel to generate electricity. The assessment of the RLSC may be triggered when the *market participant* requests to use the more expensive fuel through the mitigation process[7] but fails to provide satisfactory supporting evidence of the fuel consumption.

[7] For more information on this mitigation process, see the Process for Requesting a Reference Level Based on a More Expensive Fuel Type section in the Market Power Mitigation detailed design document.

When a *market participant* wishes to use a more expensive fuel type, the *market participant* will be able to request the *IESO* to use a reference level value based on the more expensive fuel type for the purpose of market power mitigation. *Market participants* can submit a request to use a more expensive fuel type if they believe their situation falls under one of the acceptable reasons listed in the Dual-Fuel Resource Treatment sub-section in the Market Settlement detailed design document

After a *market participant* submits a request, the *market participant* must provide evidence that the higher-cost fuel was used. The evidence needs to be provided within two *business days* of the *trading day* in which the higher-cost fuel was used. If the *market participant* fails to provide supporting information demonstrating the use of the higher-cost fuel within the specified time or if the *IESO* does not find the evidence satisfactory, the *IESO* will take the following steps:

1. The *IESO* will repeat the conduct test in the preliminary *settlement* timeframe, in the applicable market, using the lower reference level value.
2. If the resource passes the conduct test using the lower reference level, then no further steps in this process are necessary.
3. If the conduct test fails using the lower reference level, two further tests will be carried out for the MWhs that failed this conduct test:
    a. The *IESO* will determine if the make-whole payment impact test would have failed had the lower reference level been used in place of the higher reference level. If the make-whole payment impact test would have failed, the *IESO* will adjust the make-whole payment for the MWhs that failed the conduct test. The adjustment to the make-whole payment is done so it is equal to what would have been paid based on the lower reference level.
    b. For each MWh that failed the conduct test in the preliminary *settlement* timeframe, if the higher reference level is greater than or equal to the LMP[8] at the resource and the LMP at the resource is also greater than or equal to the lower reference level, the *IESO* will apply a reference level *settlement* charge.

Table 3-73: Resolution of Reference Level Settlement Charge Calculation

Attribute	Resolution
Time resolution	Hourly
Geographic resolution	Eligible *generation facilities* within Ontario: • By *delivery point*
Price accuracy (RT & DAM)	$/MWh to the nearest cent
RT *energy* quantities	MW schedule values converted to MWh values for the purposes of *settlement*, rounded to the nearest 0.1 MWh per hour or 0.001 MWh per 5-minute *metering interval*
All *real-time market settlement* data	Includes: • Real-time measurement data at applicable *delivery points*

[8] The LMP in the applicable market, either DAM or RTM, will be used.

The reference level *settlement* charge is calculated for a DAM transaction as:

$$DAM\_RLSC_{k,h}^{m} = Min\Big[0, -1 \times OP\big\{DAM\_LMP_{h}^{m}, DAM\_QSI_{k,h}^{m}, DAM\_Reference\ Level\_LowerFuel\ Cost_{k,h}^{m,t}\big\} \times P\ Multiplier\Big]$$

The reference level *settlement* charge is calculated for a real-time or pre-dispatch transaction as:

$$RT\_RLSC_{k,h}^{m} = \sum^{T} Min\Big[0, -1 \times OP\big\{RT\_LMP_{h}^{m,t}, AQEI_{k,h}^{m,t}, RT\_Reference\ Level\_Lower\ Fuel\ Cost_{k,h}^{m,t}\big\} \times P\ Multiplier\Big]$$

Where:

'T'	is the set of all *metering intervals* 't' in *settlement hour* 'h'
$DAM\_Reference\_Level\_Lower\_Fuel\_Cost_{k,h}^{m,t}$	is day-ahead reference level based on a lower fuel cost for *market participant* 'k' at *delivery point* 'm' of *settlement* hour 'h' for a given date
$RT\_\ Reference\_Level\_Lower\_Fuel\_Cost_{k,h}^{m,t}$	is real-time reference level based on a lower fuel cost for *market participant* 'k' at *delivery point* 'm' of *settlement* hour 'h' for a given date
$P\ Multiplier$	is the persistence multiplier, which accounts for persistence of not using the higher-cost fuel as originally stated during the time of request submission. Persistence multipliers will be determined as listed in Table 3-74.

Table 3-74: Persistence Multipliers

Number of Instances + Time Elapsed since last Instance	P Multiplier
First instance within a 18 month period	1
Second instance within 18 months of the last instance of substantially similar conduct (e.g., regardless of whether it is in the day-ahead *energy* or real-time e*nergy market*) by a *market participant* or its *affiliates*.	2
Third instance or additional instances within 18 months of the last instance of substantially similar conduct (e.g., regardless of whether it is in the day-ahead e*nergy market* or real-time *energy market*) by a *market participant* or its *affiliates*.	3

3.13.3 Reference Level Settlement Charge Uplift (RLSCU)

The reference level *settlement* charge uplift (RLSCU) is intended to return the RLSC charged to dual-fuel resources to all *real-time market* loads and exports on an hourly basis. The RLSCU will be allocated proportionally to loads and exports based on their real-time consumption.

$$\text{RLSC\_Uplift}_{k,h} = \sum_{K}^{M}\left(DAM\_RLSC_{k,h}^{m} + RT\_RLSC_{k,h}^{m}\right) \text{ x } \sum^{M,T}\left(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t} + RQ_{k,h}^{m,i,t}\right) / \textstyle\sum_{K}^{M,T}\left(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}\right)$$

Where:

‘K’	is the set of all *market participants* ‘k’.
‘M’	is the set of all *delivery points* ‘m’ and *intertie metering points* ‘i’.
‘T’	is the set of all *metering intervals* ‘t’ in *settlement hour* ‘h’.
‘$RQ_{k,h}^{m,i,t}$’	as defined in Section 3.5.6 Table 3-36.

3.13.4 Ex-Post Mitigation Settlement Charges

The *settlement process* will support the ex-post market power mitigation activities performed after final *settlement* for any *trading day*.

3.13.4.1 Ex-Post Mitigation for Physical Withholding Settlement Charge (EXP_PWSC)

When initial tests for market power mitigation indicate potential physical withholding, the market power mitigation processes related to ex-post testing for physical withholding, ex-post market simulation, and consultation with *market participants* may result in a *settlement* charge. This *settlement* charge will be settled on a monthly basis. For more information on the steps related to these processes, refer to Section 3.9 of the Market Power Mitigation detail design document.

These processes will test for physical withholding of *energy* and *operating reserve* in both the day-ahead market and *real-time market*. The ex-post testing for physical withholding will not test for a make-whole payment impact because the *IESO* does not provide make-whole payments for unoffered supply.

If a resource fails the conduct and impact tests for a *dispatch hour* in both the day-ahead market and the *real-time market*, the *IESO* will determine the day-ahead base *settlement* charge and the real-time base *settlement* charge for that *dispatch hour* and will levy the higher of these two base *settlement* charges.

The market power mitigation *process* will charge the *market participant* with the base *settlement* charge multiplied by the relevant persistence multiplier to determine the applicable *settlement* charge. The persistence multiplier is determined based on repeat failures by a market control entity of the conduct and impact tests for physical withholding. For more information on persistence multipliers, refer to the Market Power Mitigation detailed design document.

3.13.4.2 Ex-Post Mitigation for Economic Withholding on Uncompetitive Interties Settlement Charge (EXP_EWSC)

The market power mitigation processes related to ex-post testing for economic withholding at uncompetitive *interties*, ex-post market simulation, and consultations with *market participants* regarding the offer-based reference level and *intertie* reference level may result in a *settlement* charge. This *settlement* charge will be settled on a monthly basis.

These processes will test for economic withholding of *energy offers* or *bids*, *operating reserve* and make-whole payment impacts in both the day-ahead market and the *real-time market*.

The *IESO* will issue a *settlement* charge for each instance of economic withholding. An instance of economic withholding is defined as a single *dispatch day* on which economic withholding is found to occur on an uncompetitive *intertie* per *market participant*.

This *settlement* charge will be calculated using the hourly MW quantity that failed the conduct and impact test for economic withholding for a *dispatch day*. The procedural steps for assessing the *settlement* charge is described in Section 3.10.7 of the Market Power Mitigation detailed design.

3.13.5 Ex-Post Mitigation Settlement Charge Uplift (EXP_MSCU)

The ex-post mitigation *settlement* charge uplift (EXP_MSCU) is intended to return the EXP_PWSC and the EXP_EWSC to all *real-time market* loads and exports on an monthly basis.

The EXP_MSCU will be allocated proportionally to loads and exports based on their real-time consumption.

$$\text{EXP\_MSCU}_k = \sum_K^M (EXP\_PWSC_k^m + EXP\_EWSC_k^m) \text{ x } \sum_H^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}) / \sum_{K,H}^{M,T} \left(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}\right)$$

Where:

‘K’ is the set of all *market participants* ‘k’.

‘M’ is the set of all *delivery points* ‘m’ and *intertie metering points* ‘i’.

‘H’ is the set of all *settlement hours* ‘h’ in the month.

‘T’ is the set of all *metering intervals* ‘t’ in *settlement hour* ‘h’.

– **End of Section –**

4 Market Rule Requirements

The *market rules* govern the *IESO-controlled grid* and establish and govern the *IESO-administered markets*. The *market rules* codify obligations, rights and authorities for both the *IESO* and *market participants*, and the conditions under which those rights and authorities may be exercised and those obligations met.

This section is intended to provide an inventory of the changes to *market rule* provisions required to support the Market Settlement detailed design, and is intended to guide the development of *market rule* amendments. This inventory is based on version 1.0 of the detailed design, and any revisions required to this section as a result of design changes to version 1.0 will be incorporated in the *market rule amendment* process. As a result, the inventory will not be updated after its publication in version 1.0 of this detailed design.

This inventory is not meant to be an exhaustive list of required rule changes, but is a "snapshot" in time based on the current state of design development of this specific design document. Resulting *market rule amendments* will incorporate the integration of the individual design documents.

New and amended Chapter 11 defined terms: These terms will be consolidated in a single document at a later time as part of the *market rule amendment* process, and will support multiple design documents.

The inventory is developed in Table 4-1, which describes the impacts to the *market rules* and classifies them into the following three types:

- Existing – no change: Identifies those provisions of the existing *market rules* that are not impacted by the design requirements;
- Existing – requires amendment: Identifies those provisions of the existing *market rules* that will need to be amended to support the design requirements; and
- New - identifies new *market rules* that will likely need to be added to support the design requirements.

Table 4-1: Market Rules Impacts

Market Rule Section [Chapter. No.] [Section no.]	**Type**	**Topic**	**Requirement**
NOTE: The *market rules* inventory below is subject to change pending the completion of the DAM Calculation Engine, the PD Calculation Engine, and the RT Calculation Engine detailed design documents.			
Chapter 8 – Physical Bilateral Contracts and Financial Markets			
Chapter 8, Section 1	Existing - requires amendment	Introductory Rules	This section sets out the purpose of this Chapter including the rights and obligations of the submission of *physical bilateral contract data* by *market participants* and the use of such data by the *IESO*. • Provisions unaffected by the design changes specified in the Market Settlement detailed design document.

Market Rule Section [Chapter. No.] [Section no.]	Type	Topic	Requirement
			• As a matter of clean-up, the terms “market participants” and “physical bilateral contract data” in Section 1.1.1.1 need to be italicized. Overlap: Grid and Market Operations Integration, Offers, Bids and Data Inputs, DAM Calculation Engine, PD Calculation Engine, and RT Calculation Engine detailed design documents.
Chapter 8, Section 2	Existing - requires amendment	Physical Bilateral Contract Data and Quantities	This section sets out the *market rules* around the content, submission and revision of bilateral contract data. • Section 2.1.1 needs to be expanded to include the day-ahead market. • Section 2.1.2.2 needs to be updated to delete the current prices (*hourly Ontario energy price*) and include the new prices (day-ahead market prices and *real-time market prices (*Note: may be covered under the definition of the existing *energy market* price)). The net *energy market settlement credit* will be replaced by the Hourly Physical Transaction Settlement Amount and the Hourly Physical Transaction Settlement Amount – Non-Dispatchable Load. • As a matter of clean-up, Sections 2.4.11 needs to be revised to remove the italicization from the term “purposes” in “*settlement* purposes”. Overlap: Grid and Market Operations Integration, Offers, Bids and Data Inputs, DAM Calculation Engine, PD Calculation Engine, and RT Calculation Engine detailed design documents.
Chapter 8, Section 2	Existing - no change	Physical Bilateral Contract Data and Quantities	This section sets out the *market rules* around the content, submission and revision of bilateral contract data. • Provisions for the following sections unaffected by design changes specified in the Market Settlement detailed design document: o Section 2.3 The Form of Bilateral Contract Data o Section 2.4 Submitting and Revising Physical Bilateral Contract Data • The *market rules* for these sections may be impacted by the detailed design documents listed below. Overlap: Grid and Market Operations Integration, Offers, Bids and Data Inputs, DAM Calculation Engine, PD Calculation Engine, and RT Calculation Engine detailed design documents.

Market Rule Section [Chapter. No.] [Section no.]	**Type**	**Topic**	**Requirement**
Chapter 8, Section 3	Existing - no change	[Intentionally left blank – section deleted]	• Section previously deleted, no change required.
Chapter 8, Section 4	Existing - requires amendment	The Transmission Rights Market	This section sets out the *market rules* around the obligations and operations of the *transmission rights market*. • Provisions unaffected by the design changes specified in the Market Settlement detailed design document. • As a matter of clean-up, Section 4.4.1.1 needs to be revised to remove the italicization of the term “price” in “TR *settlement* price”. • As a matter of clean-up, Section 4.9.3 needs to be revised to remove the italicization from the term “purposes” in “*settlement* purposes”. • As a matter of clean-up, Section 4.13.10 needs to be revised to remove the term “facsimile”. Note: Refer to the Publishing and Reporting Market Information detailed design document for publishing details for Section 4.12 - Pre-auction Publication and Section 4.16 - Post-Auction Notification and Publication. Overlap: Market Billing and Funds Administration and Publishing and Reporting Market Information detailed design documents.
Appendix 8.1	Existing - no change	Mathematical Formulation of the TR Objective Function and Constraints	This section describes the objective function used to determine the number of *transmission rights* to be awarded to each *TR bidder* and sold by each *TR offeror* in a given round of a *TR auction*. • Provisions unaffected by the design changes specified in the Market Settlement detailed design document.
Appendix 8.2	Existing - no change	[Intentionally left blank]	• Section previously deleted, no change required.
Chapter 9 - Settlements and Billing			
Chapter 9, Section 1	Existing - requires amendment	Introductory Rules	This section sets out the purpose of this Chapter, including the rights and obligations of *market participants* and of the *IESO* in determining, billing and payments related to the *IESO-administered markets*, including the *real-time markets* and the *procurement markets*. Section 1.1 - Application and Purpose • Section 1.1.2 needs to be amended as follows: o Remove congestion management (Section 1.1.2.4);

Market Rule Section [Chapter. No.] [Section no.]	**Type**	**Topic**	**Requirement**
			- Section 1.1.2.14 needs to be amended from “rebates and other payments arising from market power mitigation measures” to “market power mitigation”; - Remove the day-ahead commitment process (Section 1.1.2.15); - Section 1.1.2.17 needs to be amended to remove “*capacity based demand response program*”; - Section 1.1.2.18 needs to be updated to “real-time ramp-down *settlement* amount”; and - This section needs to be expanded to include the day-ahead market (note: the *energy market* definition may be updated to include the day-ahead market). • As a matter of clean-up, the term “market participants” in Section 1.1.1.2 and the term “amount” in Section 1.1.2.18 need to be italicized. Overlap: Market Billing and Funds Administration detailed design document
Chapter 9, Section 1	Existing - no change	Introductory Rules	This section sets out the purpose of this Chapter, including the rights and obligations of *market participants* and of the *IESO* in determining, billing and payments related to the *IESO-administered markets*, including the *real-time markets* and the *procurement markets*. • Provisions for the Section 1.2 – Regulated Settlement Amounts and Related Payment Charges unaffected by design changes specified in the Market Settlement detailed design document. Overlap: Market Billing and Funds Administration detailed design document
Chapter 9 Section 2	Existing - requires amendment	Settlement Data Collection and Management	This section sets out the *market rules* around the collection and management of *settlement* data. • Section 2.1, specifically Section 2.1.1A.5 on Capacity Based Demand Response needs to be deleted. • Section 2.4B – a new section may be required for the collection of data for virtual transactions. • Section 2.6 – Collection of Physical Bilateral Contract Data needs to be revised. The references to Chapter 9, Section 3.1.6, specifically in Sections 2.6.3 and 2.6.4, need to be updated to the new Chapter 9, 3B section. • Section 2.10 needs to be expanded by including the day-ahead market prices (note: the *market price* definition

Market Rule Section [Chapter. No.] [Section no.]	**Type**	**Topic**	**Requirement**
			will be updated to include the day-ahead market) and market power mitigation data. Overlap: Revenue Meter Registration detailed design document
Chapter 9, Section 2	Existing - no change	Settlement Data Collection and Management	This section sets out the *market rules* around the collection and management of *settlement* data. • Provisions for the following sections unaffected by design changes specified in the Market Settlement detailed design document: o Section 2.1A – Station Service o Section 2.2 – Metering Data Recording and Collection Frequency o Section 2.3 – Collection and Validation of Metering Data o Section 2.4 – Section previously deleted, no change. o Section 2.4A – Delivery Points o Section 2.5 – Collection of Interchange Schedule Data o Section 2.7 – Collection of Transmission Rights (TR) Data o Section 2.8 – Section previously deleted, no change o Section 2.9 – Collection of Ancillary Service Data o Section 2.11 – Settlement Record Retention, Confidentiality, and Reliability Overlap: Revenue Meter Registration detailed design document
Chapter 9, Section 3	Existing - requires amendment	Determination of Hourly Settlement Amounts	This section sets out the *market rules* around the determination of hourly *settlement amounts*. This section will be deleted and replaced by Section 3B. The changes to each of the sections are detailed below. • Section 3.1 – Hourly Settlement Variables and Data will be moved to new section 3B. The section will be amended to remove retired variables and amended to include new variables. • Section 3.2 – section previously deleted, no change required.

Market Rule Section [Chapter. No.] [Section no.]	**Type**	**Topic**	**Requirement**

			• Section 3.3 – Hourly Settlement Amounts in the Real-Time Energy Market
			  o Sections 3.3.1 and 3.3.2 need to be deleted as it is no longer required under the Market Renewal Program (MRP).
			  o Section 3.3.3 – section previously deleted, no change required.
			• Section 3.4 – Hourly Settlement Amounts for Operating Reserve will be moved to new section 3B (replaced by the Hourly Operating Reserve Settlement Amount).
			• Section 3.5 – Hourly Settlement Amounts for Congestion Management will be deleted as it is no longer required under MRP.
			• Section 3.5A – Hourly Settlement Amounts for Ramp-Down will be moved to new section 4A, (replaced by Real-Time Ramp-Down Settlement Amount).
			• Section 3.6 – Hourly Settlement Amounts for Transmission Rights and Charges will be moved to new section 3B.
			• Section 3.7 – section previously deleted, no change required.
			• Section 3.8 – Hourly Settlement Amounts for Operating Deviations will be moved to new section 3B (the “operating reserve shortfall settlement debit” will be replaced by the Real-Time Operating Reserve Shortfall Debit).
			• Section 3.8A – Hourly Settlement Amounts for Intertie Offer Guarantees will be moved to new section 3B (replaced by Real-Time Intertie Offer Guarantee).
			• Section 3.8B – Day Ahead Import Failure Charge will be deleted as it is no longer required under MRP.
			• Section 3.8C – Real-Time Import and Real-Time Export Failure Charges will be moved to new section 3B.
			• Section 3.8D – Day Ahead Export Failure Charge will be deleted as it is no longer required under MRP.
			• Section 3.8E – Day Ahead Linked Wheel Failure Charge will be deleted as it is no longer required under MRP.
			• Section 3.8F Day-Ahead Generator Withdrawal Charge will be deleted as it is no longer required under MRP.
			• Section 3.9 – Hourly Uplift Settlement Amounts

Market Rule Section [Chapter. No.] [Section no.]	**Type**	**Topic**	**Requirement**
			o Sections 3.9.1 (*hourly uplift settlement amount* equation) and 3.9.2 (allocation of *hourly uplift*) will move to new section 3B. The formulation for the *hourly uplift settlement amount* will be amended to include the new *settlement amounts* and amended to remove the deleted *settlement amounts*. o Section 3.9.3 will move to new section 3B. The market rule around the disaggregation of the non-hourly *settlement amounts* on the *settlement statements* may be moved to the section on non-hourly *settlement amounts* in new section 4A. o Section 3.9.4 will be deleted as the day-ahead *intertie offer* guarantee *settlement* and the day-ahead import failure charge are no longer required under MRP. o Section 3.9.5 will be deleted as the *IESO* has the software capability.
Chapter 9, Section 3A	New	Two-Settlement System	This new section sets out the *market rules* around the obligations and operations of the two-*settlement* system. • New section 3A.1 – the *IESO* will operate a two-*settlement* system to support the day-ahead market and the *real-time market*. • New section 3A.2 – the two-*settlement* system will consist of *settlement amounts* from the first *settlement* and the second *settlement*. New section 3A.2.1 – *settlement amounts* from the first *settlement* includes *settlements amounts* for *energy* and *operating reserve* including *settlement amounts* that are calculated using *settlement* data from the day-ahead calculation engine. • New section 3A.2.2 – *settlement amounts* from the second *settlement* include *settlement amounts* for *energy* and *operating reserve* calculated using *settlement* data from the day-ahead calculation engine reconciled with *real-time market settlement* results. • New section 3A.3 –*settlement amounts* from the first *settlement* and the second *settlement* will be included on the *invoice*. • The first *settlement amounts* include the following: o The first *settlement* calculation of the Hourly Physical Transaction Settlement Amount.

Market Rule Section [Chapter. No.] [Section no.]	**Type**	**Topic**	**Requirement**
			o The first *settlement* calculation of the Hourly Virtual Transaction Settlement Amount. o The first *settlement* calculation of the Hourly Operating Reserve Settlement Amount. • The second *settlement amounts* include the following: o The second *settlement* calculation of the Hourly Physical Transaction Settlement Amount. o The second *settlement* of the Hourly Physical Transaction Settlement Amount – Non-Dispatchable Load. o The second *settlement* calculation of the Hourly Virtual Transaction Settlement Amount. o The second *settlement* calculation of the Hourly Operating Reserve Settlement Amount. o The second *settlement* calculation of the Day-Ahead Market Operating Reserve Uplift.
Chapter 9, Section 3B.X	New	Determination of Hourly Settlement Amounts	This new section sets out the *market rules* around the determination of hourly *settlement amounts*. • New section – Hourly Settlement Variables and Data will include the hourly *settlement amounts* for the *hourly markets* using the prices and quantities described in this section as follows: o New section will include the day-ahead market prices and quantities from the day-ahead market calculation engine and provided directly to the *settlement process*. o New section will include the *pre-dispatch* prices and quantities from the *pre-dispatch* calculation engine and provided directly to the *settlement process*. o New section will include the *real-time market* prices and quantities from the *real-time market* calculation engine and provided directly to the *settlement process*. o New section will include the *operating reserve* prices and quantities for the three types “r” of *class r reserves*. o New section will include the *physical bilateral contract quantities* (day-ahead market and *real-time market*) that will be provided directly to the *settlement process*.

Market Rule Section [Chapter. No.] [Section no.]	**Type**	**Topic**	**Requirement**
			o New section will include the day-ahead market *transmission rights* data that will be provided directly to the *settlement process*. o New section will include the market power mitigation data that will be provided directly to the *settlement process*. o New section will include the allocated physical quantities that will be determined by the *IESO*. • New section – Hourly Settlements Amounts in the Day-Ahead Market and the Real-Time Energy Market. For the purposes of this inventory, this section is broken out into subsections by *settlement amount* as follows: o Hourly Physical Transaction Settlement Amount o Hourly Physical Transaction Settlement Amount – Non-Dispatchable Load o Hourly Operating Reserve Settlement Amount o Hourly Virtual Transaction Settlement Amount o Day-Ahead Market Make-Whole Payment o Day-Ahead Market Balancing Credit o Real-Time Make-Whole Payment o Generator Failure Charge – Market Price Component o Real-Time Intertie Offer Guarantee o Real-Time Import Failure Charge o Real-Time Export Failure Charge Overlap: DAM Calculation Engine, PD Calculation Engine, and RT Calculation Engine detailed design documents.
Chapter 9, Section 3B.X	New	Hourly Physical Transaction Settlement Amount	This new section sets out the *market rules* around the determination of the Hourly Physical Transaction Settlement Amount. New section – “Hourly Physical Transaction Settlement Amount – First Settlement”. • Eligibility criteria: o *Facility*/transactions types: *boundary entity, dispatchable load*, non-dispatchable *generation facility*, non-quick start *generation facility*, price responsive load, and *quick start facility*

Market Rule Section [Chapter. No.] [Section no.]	**Type**	**Topic**	**Requirement**
			• This section will include the formulation of the Hourly Physical Transaction Settlement Amount as follows: o For *physical bilateral contracts*, the difference between the day-ahead market quantities sold and bought multiplied by the applicable day-ahead market price (nodal for *delivery points* and zonal for *intertie metering points*). o For all *facility*/transaction types except price responsive loads, the difference between the day-ahead market scheduled quantity for injection and the day-ahead market quantity scheduled for withdrawal multiplied by the applicable day-ahead market price (nodal for *delivery points* and zonal for *intertie metering points*). o For price responsive loads, the day-ahead market quantity scheduled for withdrawal multiplied by the day-ahead market price for two *delivery point* types. The first is for *delivery points* for price responsive loads and the second is for *delivery points* for price responsive loads used as physical hourly *demand response* resource to fulfil *capacity obligations*. New section – "Hourly Physical Transaction Settlement Amount – Second Settlement". • Eligibility criteria: o *Facility*/transactions types: *Boundary entity*, *dispatchable load*, non-dispatchable *generation facility*, non-quick start *generation facility*, price responsive load, *quick start facility* • This section will include the formulation of Hourly Physical Transaction Settlement Amount as follows: o For *physical bilateral contracts*, the difference between the *real-time market* quantities sold and bought multiplied by the applicable *real-time market* price (nodal for *delivery points* and *intertie settlement* price for *intertie metering points*). o For all *facility*/transaction types except *non-dispatchable loads* and price responsive loads, the difference between the day-ahead market quantity scheduled for injection and the actual

Market Rule Section [Chapter. No.] [Section no.]	**Type**	**Topic**	**Requirement**
			injection quantity, less the difference between the day-ahead market quantity scheduled for withdrawal and the actual withdrawal quantity, multiplied by the applicable day-ahead market price (nodal for *delivery points* and *intertie settlement* price for *intertie metering points*). o For price responsive loads, the difference between the day-ahead market quantity scheduled for withdrawal and the actual withdrawal quantity, multiplied by the *real-time market* price. For price responsive loads used as physical hourly *demand response* resources to fulfil *capacity obligations*, the day-ahead market quantity scheduled for withdrawal multiplied by the *real-time market* price.
Chapter 9, Section 3B.X	New	Hourly Physical Transaction Settlement Amount for Non-Dispatchable Loads	This new section sets out the *market rules* around the determination of the Hourly Physical Transaction Settlement Amount for Non-Dispatchable Loads. • Eligibility criteria: o *Facility*/transaction types: *non-dispatchable load*; and o The *non-dispatchable load* withdraws *energy* in real-time. • The section will include the formulation of the Hourly Physical Transaction Settlement Amount for Non-Dispatchable Loads as follows: o The o sum of the day-ahead market price and the load forecast deviation charge multiplied by the actual *energy* withdrawn. Where: o The load forecast deviation charge is the sum of: ▪ The difference between the actual withdrawal and the day-ahead market quantity scheduled for withdrawal multiplied by the *real-time market* price for *non-dispatchable loads*, less the day-ahead market quantity scheduled for withdrawal multiplied by the *real-time market* price for *hourly demand response* resources that are not registered as a price responsive load, divided by the total actual

Market Rule Section [Chapter. No.] [Section no.]	**Type**	**Topic**	**Requirement**
			withdrawal for *non-dispatchable loads*; and ▪ The difference between the day-ahead market quantity scheduled for withdrawal and the actual withdrawal multiplied by the day-ahead market price for *non-dispatchable loads*, added to the day-ahead market quantity scheduled for withdrawal multiplied by the day-ahead market price for *hourly demand response* resources that are not registered as a price responsive load, divided by the total actual withdrawal for *non-dispatchable loads*.
Chapter 9, Section 3B.X	New	Hourly Operating Reserve Settlement Amount	This new section sets out the *market rules* around the determination of the Hourly Operating Reserve Settlement Amount. New section – "Hourly Operating Reserve Settlement Amount – First Settlement". • Eligibility criteria: o *Facility*/transactions types: *boundary entity*, *dispatchable load*, non-quick start *generation facility*, *quick start facility* • The section will include the formulation of the Hourly Operating Reserve Settlement Amount – First Settlement as follows: o The day-ahead market scheduled quantity of *operating reserve* multiplied by the day-ahead market price (for each *class r reserve).* New section – "Hourly Operating Reserve Settlement Amount – Second Settlement". • Eligibility criteria: o *Facility*/transactions types: *boundary entity*, *dispatchable load*, non-quick start *generation facility*, *quick start facility* • The section will include the formulation of the Hourly Operating Reserve Settlement Amount – Second Settlement as follows: o The difference between the *real-time market* quantity and the day-ahead market quantity multiplied by the *real-time market operating reserve* price.

Market Rule Section [Chapter. No.] [Section no.]	**Type**	**Topic**	**Requirement**
			• The Hourly Operating Reserve Settlement Amount – First and Second Settlements will be recovered from *market participants* through the "Day-Ahead Market Operating Reserve Uplift". The "Day-Ahead Market Operating Reserve Uplift" will be allocated on a pro-rata basis to all *real-time market* loads and exports on an hourly basis.
Chapter 9, Section 3B.X	New	Hourly Virtual Transaction Settlement Amount	This new section sets out the *market rules* around the determination of the Hourly Virtual Transaction Settlement Amount. New section – "Hourly Virtual Transaction Settlement Amount – First Settlement". • Eligibility criteria: o *Facility*/transactions types: Virtual transaction only • The section will include the formulation of the Hourly Virtual Transaction Settlement Amount as follows: o The difference between the day-ahead market virtual quantity scheduled for injection and the day-ahead market virtual quantity scheduled for withdrawal multiplied by day-ahead market price. New section – "Hourly Virtual Transaction Settlement Amount – Second Settlement". • Eligibility criteria: o *Facility*/transactions types: Virtual transaction only • The section will include the formulation of the Hourly Virtual Transaction Settlement Amount as follows: o The difference between the day-ahead market virtual quantity scheduled for injection and the day-ahead market virtual quantity scheduled for withdrawal multiplied by *real-time market* price.
Chapter 9, Section 3B.X	New	Day-Ahead Market Make-Whole Payment	This new section sets out the *market rules* around the determination of the Day-Ahead Market Make-Whole Payment. • Eligibility criteria: o *Facility*/transaction types: *boundary entity*, *dispatchable load*, hydroelectric *generation facility*, non-quick start *generation facility*, price responsive load, and *quick start facility*

Market Rule Section [Chapter. No.] [Section no.]	**Type**	**Topic**	**Requirement**
			o For *generation units* where capacity is committed to an external *control area*: ▪ The *generation unit* is not called by the *control area operator* to support an *energy* export prior to being scheduled in the day-ahead market. ▪ The *generation unit* is not called by the *control area operator* to support an *energy* export after being scheduled in the day-ahead market. o For a hydroelectric *generation facility*: ▪ Is scheduled at its minimum daily *energy* limit for a *trading day*; or ▪ Is scheduled above it minimum daily *energy* limit but the *facility* was only able to satisfy its minimum daily *energy* limit after taking into account its minimum hourly outputs for a *trading day*. o For a non-*quick start facility*: ▪ Not a ramp-up period. • The section will include the formulation for the Day-Ahead Market Make-Whole Payment as follows: o For a *boundary entity*, *dispatchable load*, *quick start facility*, and not a *quick start facility*, the sum of: ▪ The difference between day-ahead market price and the *market participant's* day-ahead market *offer* (or day-ahead market *bid*) multiplied by the difference between the day-ahead market schedule and the day-ahead market economic operating point [operating profit function]; and ▪ The difference between the day-ahead market *operating reserve* prices and the *market participant's* day-ahead market *operating reserve offer* (or day-ahead market *operating reserve bid*) multiplied by the difference between the day-ahead market *operating reserve* schedule and the day-ahead market economic operating

Market Rule Section [Chapter. No.] [Section no.]	**Type**	**Topic**	**Requirement**
			point for each *class r reserve* [operating profit function]. o For a (cascade) hydroelectric *generation facility*, the sum of: ▪ The difference between day-ahead market price and the *market participant's* day-ahead market *offer* multiplied by the difference between the day-ahead market schedule and the day-ahead market economic operating point [operating profit function]; and ▪ The difference between the day-ahead market *operating reserve* prices and the *market participant's* day-ahead market *operating reserve offer* multiplied by the difference between the day-ahead market *operating reserve* schedule and the day-ahead market economic operating point for each *class r reserve* [operating profit function]. o For a *pseudo-unit*: ▪ The formulation will be the same as the NSQ *generation facility* with the following differences: • For a combustion turbine associated with a *pseudo-unit*, the Derived Interval Price Curve is used for the day-ahead market *offer*; and • For a steam turbine associated with a *pseudo-unit*, the Derived Interval Price Curve is used for the day-ahead market *offer* and the Derived Interval Guarantee Quantity is used for the day-ahead market schedule. • The Day-Ahead Market Make-Whole Payments (and the Day-Ahead Generator Offer Guarantee) will be recovered from *market participants* through: o the "Day-Ahead Market Make-Whole Payment Uplift"; and

Market Rule Section [Chapter. No.] [Section no.]	**Type**	**Topic**	**Requirement**
			o the “Day-Ahead Market Reliability Scheduling Uplift”. • The “Day-Ahead Market Make-Whole Payment Uplift”: o Does not include the Day-Ahead Market Make-Whole Payments made to imports and the Day-Ahead Market Generator Offer Guarantee payments to a not a *quick start facility* scheduled in the *reliability* scheduling pass of the Day-Ahead Market Calculation Engine; and is o Allocated on a pro-rata basis to all *real-time market* loads and exports on a daily basis. • The “Day-Ahead Market Reliability Scheduling Uplift”: o Includes the Day-Ahead Market Make-Whole Payments made to imports and the Day-Ahead Market Generator Offer Guarantee payments to a not a *quick start facility* scheduled in the *reliability* scheduling pass of the Day-Ahead Market Calculation Engine. o Is allocated as follows: ▪ First step: Allocated on a pro-rata basis across virtual supply transactions. ▪ Second step: The remainder will be allocated on a pro-rata basis to all *real-time market* loads and exports on a daily basis.
Chapter 9, Section 3B.X	New	Day-Ahead Market Balancing Credit	This new section sets out the *market rules* around the determination of the Day-Ahead Market Balancing Credit. • This section will include the eligibility criteria as follows: o *Facility*/transaction type: *boundary entity*, *generation facility* o For all eligible *facility* types, the *facility* must respond and/or must follow their *dispatch instructions.* o For *boundary entities*, a control room action resulting in the transaction being dispatched down from its day-ahead market schedule and has a *real-time market* schedule less than its real-time economic operating point. • The section will include the formulation of the Day-Ahead Market Balancing Credit as follows.

Market Rule Section [Chapter. No.] [Section no.]	**Type**	**Topic**	**Requirement**
			o For *generation facilities*, the sum of: ▪ The difference between the day-ahead market price and the *real-time market* price multiplied by the difference between the day-ahead market schedule and the *real-time market* schedule; and ▪ The difference between the day-ahead market *operating reserve* prices and the *real-time market operating reserve* prices multiplied by the difference between the day-ahead market *operating reserve* schedule and *real-time market operating reserve* schedule for each *class r reserve*. o For *boundary entities* (import transactions only), the sum of: ▪ The minimum of the real-time lost opportunity cost economic operating point and the day-ahead market schedule less the scheduled quantity of *energy* injected multiplied by the difference between *intertie settlement* price and the day-ahead market price, added to the difference between the day-ahead market price and the *market participant's real-time market energy offers* for the minimum of the real-time lost opportunity cost economic operating point and the day-ahead market schedule [operating profit function]; and ▪ The minimum of the real-time lost opportunity cost economic operating point for *operating reserve* and the day-ahead market *operating reserve* schedule less the *real-time market operating reserve* schedule multiplied by the difference between the *intertie settlement* price for *operating reserve* and the day-ahead market price, added to the difference between the day-ahead market *operating reserve* price and the *market participant's real-time market operating reserve offers* for the minimum of the real-time lost opportunity cost economic operating

Market Rule Section [Chapter. No.] [Section no.]	Type	Topic	Requirement
			point and the day-ahead market schedule [operating profit function]. ▪ Note: When the price in the *market participant's real-time market energy offer* is less than the day-ahead market *energy* price, the price (in the respective *price-quantity pair*) will be replaced by the day-ahead market *energy* price. ▪ Note: When the *market participant's real-time market operating reserve offer* is less than the day-ahead market *operating reserve* price, the price (in the respective *price-quantity pair*) will be replaced by the day-ahead market *operating reserve* price. o For *boundary entities* (export transactions only): ▪ The minimum of the real-time lost opportunity cost economic operating point and the day-ahead market schedule less the scheduled quantity of *energy* withdrawn multiplied by the difference between *intertie settlement* price and the day-ahead market price, added to the difference between the day-ahead market price and the *market participant's real-time market energy bids* for the minimum of the real-time lost opportunity cost economic operating point and the day-ahead market schedule [operating profit function]. ▪ Note: When the price in the *market participant's real-time market energy bid* is greater than the day-ahead market *energy* price, the price (in the respective *price-quantity pair*) will be replaced by the day-ahead market *energy* price. • The Day-Ahead Market Balancing Credit will be recovered from *market participants* through the “Day-Ahead Market Balancing Credit Uplift”. The “Day-Ahead Market Balancing Credit Uplift” will be allocated on a pro-rata basis to all *real-time market* loads and exports on an hourly basis.

Market Rule Section [Chapter. No.] [Section no.]	**Type**	**Topic**	**Requirement**
Chapter 9, Section 3B.X	New	Real-Time Make-Whole Payment	This new section sets out the *market rules* around the determination of the Real-Time Make-Whole Payment. • This section will include the eligibility criteria as follows: o *Facility*/transaction types: *boundary entity*, dispatchable *generation facility*, *dispatchable load* o Not dispatched up or down relative to its associated economic operating point at the request of the *market participant*. o Not a ramp-up period. o For a hydroelectric *generation facility*: ▪ Is scheduled above its minimum daily *energy* limit for a *trading day*; or ▪ Is scheduled above its minimum daily *energy* limit and is able to achieve more than its minimum daily *energy* limit across the *trading day*. o For a combustion turbine associated to a *pseudo-unit*: ▪ Scheduled to inject at or above its *minimum loading point* in the *real-time market*; and ▪ Not an interval where it is ramping to meet its *minimum loading point* or ramping down to come offline. o For a steam turbine associated to a *pseudo-unit*: ▪ At least one associated combustion turbine is scheduled above its *minimum loading point* in the *real-time market*. • This section will include the formulation of the Real-Time Make-Whole Payment as follows: o For a dispatchable *generation facility*, the sum of: ▪ The difference between the operating profit for the minimum of the *real-time market* schedule and the actual injection and the operating profit for the maximum of the real-time economic operating point and the day-ahead market schedule; and

Market Rule Section [Chapter. No.] [Section no.]	**Type**	**Topic**	**Requirement**
			▪ The difference between the operating profit for the real-time economic operating point and the operating profit for the maximum of the *real-time market* schedule and the actual injection. ▪ Note: In any interval where the *real-time market* schedule and the actual injection are both not less than the real-time economic operating point or are both not greater than the economic operating point, the first and second terms (i.e. the first and second bullets) will be set to zero. ▪ Note: When the price in the *market participant's real-time market energy offer* is less than *real-time market energy* price, the price (in the respective *price-quantity pair*) will be replaced by the *real-time market energy* price in the second term (i.e. the second bullet). o For a *dispatchable load*, the sum of: ▪ The difference between the operating profit for the minimum of the *real-time market* schedule and the actual withdrawal and the operating profit for the maximum of the real-time economic operating point and the day-ahead market schedule; and ▪ The difference between the operating profit for the real-time economic operating point and the operating profit for the maximum of the *real-time market* schedule and the actual withdrawal. ▪ Note: In any interval where the *real-time market* schedule and the actual withdrawal are both not less than the real-time economic operating point or are both not greater than the economic operating point, the first and second terms (i.e. the first and second bullets) will be set to zero. ▪ Note: When the price in the *market participant's real-time market energy*

Market Rule Section [Chapter. No.] [Section no.]	**Type**	**Topic**	**Requirement**
			bid is less than the day-ahead market *energy* price, the price (in the respective *price-quantity pair*) will be replaced by the day-ahead market *energy* price in the second term (i.e. the second bullet). o For a dispatchable *generation facility* or a *dispatchable load*, the sum of: ▪ The difference between the operating profit for the *real-time market operative reserve* schedule and the operating profit for the maximum of the real-time economic operating point and the day-ahead market *operative reserve* schedule; and ▪ The difference between the operating profit for the real-time economic operating point for *operating reserve* and the operating profit for the *real-time market operating reserve* schedule. ▪ Note: When the *market participant's real-time market operating reserve offer* is greater than the *real-time market operating reserve* price, the price (in the respective *price-quantity pair*) will be replaced by the *real-time market operating reserve* price in the second term (i.e. second bullet). o For a *boundary entity* (import transaction): ▪ The difference between the operating profit for maximum of the *real-time market operating reserve* schedule and the day-ahead market *operating reserve* schedule and the operating profit for the maximum of the real-time economic operating point for *operating reserve* and the day-ahead market *operating reserve* schedule. o For a *boundary entity* (export transaction) where there is a *pre-dispatch* pricing discrepancy: ▪ The difference between the operating profit for the maximum of the scheduled quantity for withdrawal and the day-ahead market schedule and

Market Rule Section [Chapter. No.] [Section no.]	**Type**	**Topic**	**Requirement**
			operating profit for the maximum of the real-time economic operating point and the day-ahead market schedule (using the minimum of the *intertie settlement* price and the *pre-dispatch* price). o For a *boundary entity* (export transaction) where there is a manual dispatch out of merit: ▪ The difference between the operating profit for the maximum of the *real-time market* schedule and the day-ahead market schedule and the operating profit for the maximum of the real-time economic operating point and the day-ahead market schedule. o For a *pseudo-unit*: ▪ The formulation will be the same as a dispatchable *generation facility* with the following differences: • For a combustion turbine associated with a *pseudo-unit*, the Derived Interval Price Curve is used for the *real-time market offer*; and • For a steam turbine associated with a *pseudo-unit*, the Derived Interval Price Curve is used for the *real-time market offer* and the Derived Interval Guarantee Quantities (day-ahead market and *real-time market)* are used for the day-ahead market schedule and the *real-time market* schedule. • The Real-Time Make-Whole Payments will be recovered from *market participants* through the "Real-Time Make-Whole Payment Uplift". The "Real-Time Make-Whole Payment Uplift" will be allocated on a pro-rata basis to all *real-time market* loads and exports on an hourly basis.
Chapter 9, Section 3B.X	New	Generator Failure Charge – Market Price Component	This new section sets out the *market rules* around the determination of the Generator Failure Charge – Market Price Component.

Market Rule Section [Chapter. No.] [Section no.]	Type	Topic	Requirement
			• Eligible *facility*/transaction types: non-quick start *generation facility* • Exception requirements: The generation failure charge will not be applied when a failure to meet the *pre-dispatch* commitment is outside the *market participant's* control. The reasons include: o Forced outages (out of the *market participant's* control), transmission outages, force majeure, dispatched down by the *IESO* for *reliability* reasons, and *reliability* commitments. • The Generator Failure Charge – Market Price Component will be assessed when one of the following three scenarios occurs and does not fall under the exception requirement above: o Failure to ramp to *minimum loading point* on schedule; o Failure to operate until the end of its commitment period. This includes hours when the *generation unit* is extended in *pre-dispatch* beyond its initial commitment; and o Failure to operate for any hours (i.e. failure to come online). o Note: For each type of failure, the failure intervals (i.e. period subject to the failure charge assessment) will be defined in the *market rules*. • For a combustion turbine associated to a *pseudo-unit*, the Generator Failure Charge – Market Price Component will be assessed when one of the following scenarios occurs and does not fall under the exception requirement above: o Failure to ramp to *minimum loading point* on schedule; o Failure to operate until the end of its commitment period of its associated *pseudo-unit*. This includes hours when the *generation unit* is extended in *pre-dispatch* beyond its initial commitment; o Failure to operate for any hours (i.e. failure to come online); and o The associated *pseudo-unit* activated its single cycles flag at any time during its commitment

Market Rule Section [Chapter. No.] [Section no.]	**Type**	**Topic**	**Requirement**
			period or an extension of its commitment period and the units has increased its price. o Note: For each type of failure, the failure intervals (i.e. period subject to the failure charge assessment) will be defined in the *market rules*. • For a steam turbine associated to a *pseudo-unit*, the Generator Failure Charge – Market Price Component will be assessed when one of the following scenarios occurs and does not fall under the exception requirement above: o Failure to ramp to *minimum loading point* on schedule by one or more of its associated combustion turbines; o Failure to operate until the end of its commitment period by one or more of its associated combustion turbines. This includes hours when the *generation unit* is extended in *pre-dispatch* beyond its initial commitment; o Failure to operate for any hours (i.e. failure to come online) by one or more of its associated combustion turbines; and o The associated *pseudo-unit(s)* activated its (their) single cycles flag(s) at any time during its commitment period or an extension of its commitment period. o Note: For each type of failure, the failure intervals (i.e. period subject to the failure charge assessment) will be defined in the *market rules*. • This section will include the formulation of the Generator Failure Charge – Market Price Component as follows: o If the *market participant* provides notice of failure less than four hours ahead of the first failure hour, or if a failure of notice is not provided by the *market participant*, then ▪ The difference between the *real-time market* price and the *pre-dispatch* price multiplied by the *pre-dispatch schedule* minus the maximum of the actual injection and the day-ahead market schedule.

Market Rule Section [Chapter. No.] [Section no.]	**Type**	**Topic**	**Requirement**
			o If the *market participant* provides greater than or equal to four hours of notice ahead of the first failure hour, then ▪ The minimum of the *real-time market* price and the hour ahead *pre-dispatch* price minus the *pre-dispatch* price multiplied by the *pre-dispatch schedule* minus the maximum of the actual injection and the day-ahead market schedule. • For a *pseudo-unit*: o For a combustion turbine associated to a *pseudo*-unit, the formulation will be the same as a non-quick start *generation unit*. o For a steam turbine associated to a *pseudo*-unit, the formulation as follows: ▪ If the *market participant* provides notice of failure less than four hours ahead of the first failure hour, or if a failure of notice is not provided by the *market participant*, then • The difference between the *real-time market* price and the *pre-dispatch* price multiplied by the steam turbine portion of the *real-time market* schedule added to the steam turbine portion of the *pre-dispatch schedule* minus the actual injection. ▪ If the *market participant* provides greater than or equal to four hours of notice ahead of the first failure hour, then • The minimum of the *real-time market* price and the hour ahead *pre-dispatch* price minus the *pre-dispatch* price multiplied by the steam turbine portion of the *real-time market* schedule added to the steam turbine portion of the *pre-dispatch schedule* minus the actual injection.

Market Rule Section [Chapter. No.] [Section no.]	**Type**	**Topic**	**Requirement**
			▪ Note: The *pre-dispatch* price used is the lowest *pre-dispatch* price of all the *pre-dispatch* runs for associated *pseudo-unit(s)* that have incurred a failure within the interval. ▪ Note: The steam turbine portion of the *real-time market* schedule is the sum of the steam turbines portions of the *pseudo-units* whose associated combustion turbines does not have a failure for the same interval. ▪ Note: The steam turbine portion of the *pre-dispatch schedule* is the sum of the steam turbine portions for *pseudo-units* that a *pre-dispatch* commitment and whose associated combustion turbines has a failure in the same interval. The *pre-dispatch* run that issued the most recent operational constraint for the interval is used. • The Generator Failure Charge – Market Price Component will be reimbursed to *market participants* through the "Generator Failure Charge – Market Price Component Uplift". The "Generator Failure Charge – Market Price Component Uplift" will be allocated on a pro-rata basis to all *real-time market* loads and exports on an hourly basis.
Chapter 9, Section 3B.X	New	Real-Time Intertie Offer Guarantee	This new section sets out the *market rules* around the determination of the Real-Time Intertie Offer Guarantee. • Eligible *facility*/transaction type: *Boundary entity* (import transaction) • The section will include the formulation for the Real-Time Intertie Offer Guarantee as follows: o The difference between the *real-time market offer* and the *intertie* scheduling price for the scheduled quantity of *energy* injected at an *intertie metering point* [operating profit function]; o Less: The difference between the *real-time market offer* and the *intertie* scheduling price for the minimum of the scheduled quantity of *energy* injected at an *intertie metering point* and the day-ahead market schedule; and o Less: The *intertie offer* guarantee offset for the *intertie* transaction.

<table>
<tr><th>Market Rule Section
[Chapter. No.] [Section no.]</th><th>Type</th><th>Topic</th><th>Requirement</th></tr>
<tr><td></td><td></td><td></td><td>The section will include the intertie offer guarantee offset process steps and formulae.
The Real-Time Intertie Offer Guarantee will be recovered from market participants through the “Real-Time Intertie Offer Guarantee Uplift”. The “Real-Time Intertie Offer Guarantee Uplift” will be allocated on a pro-rata basis to all real-time market loads and exports on an hourly basis.</td></tr>
<tr><td>Chapter 9, Section 3B.X</td><td>New</td><td>Real-Time Import Failure Charge</td><td>This new section sets out the market rules around the determination of the Real-Time Import Failure Charge.
Eligible facility/transaction type: Boundary entity (import transaction)
Exception requirements: The Real-Time Import Failure Charge will not be applied when the failure is outside the market participant’s control (i.e. failure was due to bona fide and legitimate reasons).
This section will include the formulation of the Real-Time Import Failure Charge as follows:
The minimum of:
The real-time market price, adjusted by the price bias adjustment factor and the pre-dispatch price, multiplied by the scheduling deviation quantity; and
The real-time market price multiplied by the scheduling deviation quantity.
The scheduling deviation quantity is the portion of the pre-dispatch schedule that is greater than the day-ahead market schedule and is not scheduled in real-time.
Price bias adjustment factors:
The IESO will determine the price bias adjustment factors as described in the applicable market manual.
The IESO will continue to publish the price bias adjustment factors.
The Real-Time Import Failure Charge will be reimbursed to market participants through the “Real-Time Intertie Failure Charge Uplift”. The “Real-Time Intertie Failure Charge Uplift” will be allocated on a pro-rata basis to all real-time market loads and exports on an hourly basis.</td></tr>
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Market Rule Section [Chapter. No.] [Section no.]	**Type**	**Topic**	**Requirement**
			Overlap: Publishing and Reporting Market Information detailed design document
Chapter 9, Section 3B.X	New	Real-Time Export Failure Charge	This new section sets out the *market rules* around the determination of the Real-Time Export Failure Charge. • Eligible *facility*/transaction type: *Boundary entity* (export transaction) • Exception requirements: The Real-Time Export Failure Charge will not be applied when the failure is outside the *market participant's* control (i.e. failure was due to bona fide and legitimate reasons). • This section will include the formulation of the Real-Time Export Failure Charge as follows: o The minimum of: ▪ The *pre-dispatch* price, adjusted by the price bias adjustment factor and the *real-time market* price, multiplied by the scheduling deviation quantity; and ▪ The *pre-dispatch* price multiplied by the scheduling deviation quantity. o The scheduling deviation quantity is the portion of the *pre-dispatch schedule* that is greater than the day-ahead market schedule and is not scheduled in real-time. • Price bias adjustment factors: o The *IESO* will determine the price bias adjustment factors as described in the applicable *market manual*. o The *IESO* will continue to *publish* the price bias adjustment factors. • The Real-Time Export Failure Charge will be reimbursed to *market participants* through the "Real-Time Intertie Failure Charge Uplift". The "Real-Time Intertie Failure Charge Uplift" will be allocated on a pro-rata basis to all *real-time market* loads and exports on an hourly basis. Overlap: Publishing and Reporting Market Information detailed design document
Chapter 9, Section 3B.X	New	Hourly Uplift Settlement Amounts	This new section sets out the *market rules* around the determination of the Hourly Uplift Settlement Amounts. • Will continue to be allocated on a pro-rata basis to all *real-time market* loads and exports on an hourly basis.

Market Rule Section [Chapter. No.] [Section no.]	**Type**	**Topic**	**Requirement**
			• Will include the following the *settlement amounts*: o Day-Ahead Market Operating Reserve (first and second *settlement amounts*) o Day-Ahead Market Balancing Credit o Real-Time Make-Whole Payment o Generator Failure Charge – Market Price Component o Reference Level Settlement Charge o Real-Time Intertie Offer Guarantee o Real-Time Import Failure Charge o Real-Time Export Failure Charge
Chapter 9, Section 4	Existing - no change	Non-hourly Settlement Amounts	This section sets out the *market rules* around the determination of non-hourly *settlement amounts*. This section will be deleted and replaced by Section 4A. The following sections will be moved to new Section 4A. • Provisions for the following sections unaffected by design changes specified in the Market Settlement detailed design document: o Section 4.1 – Transmission Tariff Charges o Section 4.2 – Ancillary Service Payments o Section 4.3 – Section intentionally left blank, no change o Section 4.4 – Section previously deleted, no change required o Section 4.5 – IESO Administration Charge, Penalties, and Fines o Section 4.6 – Section previously deleted, no change o Section 4.7 – TR Clearing Account Disbursements o Section 4.7A – Section previously deleted, no change o Section 4.7C – Section previously deleted, no change o Section 4.7F – Section previously deleted, no change o Section 4.7G – Forecasting for Variable Generation

Market Rule Section [Chapter. No.] [Section no.]	**Type**	**Topic**	**Requirement**
			o Section 4.7H – Section previously deleted, no change o Section 4.7I – Section previously deleted, no change o Section 47J – Capacity Obligations Overlap: Market Billing and Funds Administration detailed design document
Chapter 9, Section 4	Existing - requires amendment	Non-hourly Settlement Amounts	This section sets out the *market rules* around the determination of non-hourly *settlement amounts*. This section will be deleted and replaced by Section 4A. The changes to each of the sections are detailed below. • Section 4.7B – Real-Time Generation Cost Guarantee Payments will be deleted as it is no longer required under MRP. • Section 4.7D – Day-Ahead Production Cost Guarantee Payments will be deleted as it is no longer required under MRP. • Section 4.7E – Day-Ahead Fuel Cost Compensation Settlement Amount will be deleted as it is no longer required under MRP. • Section 4.8 – Additional Non-Hourly Settlement Amounts. This section will be moved to new Section 4A and will be revised as follows: o Delete section 4.8.1.12 – day-ahead production cost guarantee o Delete section 4.8.1.13 – day-ahead fuel cost compensation *settlement amount*. o Delete section 4.8.2.8 – day-ahead import failure charge. o Delete section 4.8.2.10 – congestion management *settlement* credit o Delete – section 4.8.2.11 – day-ahead *intertie offer* guarantee payments. o Delete section 4.8.2.14 – day-ahead generator withdrawal charge. o Delete section 4.8.2.16 – references to real-time generator cost guarantee and day-ahead production cost guarantee. o Delete section 4.8.2.17 – – reference to congestion management *settlement* credit

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[Chapter. No.] [Section no.]</th><th>Type</th><th>Topic</th><th>Requirement</th></tr>
<tr><td></td><td></td><td></td><td>o Delete section 4.8.2.18 – reference to congestion management settlement credit
o New section 4A.8.5 to include settlement amounts will be allocated on a pro-rata basis to all real-time market loads and exports on a daily basis.
Overlap: DAM Calculation Engine, PD Calculation Engine and RT Market Calculation Engine detailed design documents.</td></tr>
<tr><td>Chapter 9, Section 4A.X</td><td>New</td><td>Day-Ahead Market Generator Offer Guarantee</td><td>This new section sets out the market rules around the determination of the Day-Ahead Market Generator Offer Guarantee.
• Eligibility criteria:
o Facility/transaction types: Non-quick start generation facility;
o Minimum loading point greater than zero (0) MW;
o Minimum generation block run time greater than one hour; and
o Elapsed time to dispatch greater than one hour.
o For generation units where capacity is committed to an external control area:
▪ The generation unit is not called by the control area operator to support an energy export prior to being scheduled in the day-ahead market.
▪ The generation unit is not called by the control area operator to support an energy export after being scheduled in the day-ahead market.
• Eligibility criteria for the recovery of start-up offer:
o The generation unit must synchronize prior to the start of their minimum generation block run time, unless instructed by the IESO not to synchronize;
o The day-ahead market commitment period does not immediately follow another commitment period where a start-up cost is guaranteed; and
o The generation unit must complete its entire minimum generation block run time, unless the IESO dispatches the unit down for reliability reasons.</td></tr>
</table>

Market Rule Section [Chapter. No.] [Section no.]	**Type**	**Topic**	**Requirement**
			• Eligibility criteria for the recovery of start-up offer for a combustion turbine associated to a *pseudo-unit*: o The combustion turbine must synchronize prior to the start of their *minimum generation block run time*, unless instructed by the *IESO* not to synchronize; o The day-ahead market commitment period does not immediately follow another commitment period where a start-up cost is guaranteed; o The *generation unit* must complete its entire *minimum generation block run time*, unless the *IESO* dispatches the unit down for *reliability* reasons; and o The combustion turbine's simple cycle flag is not activated during its *minimum generation block run time*. • Eligibility criteria for the recovery of start-up offer for a steam turbine associated to a *pseudo-unit*: o At least one of the combustion turbines associated with the *pseudo-unit* has met all of its eligibility criteria. • The section will include the formulation of the Day-Ahead Market Generator Offer Guarantee as follows. The sum of: o The difference between day-ahead market price and the *market participant's* day-ahead market *offer* multiplied by the day-schedule [operating profit function] added to the day-ahead market speed no-load offer; less any revenue earned (the day-ahead market price multiplied by the day-ahead market schedule) during the ramp up period. (Variants A, B and C); o The difference between the day-ahead market *operating reserve* prices and the *market participant's* day-ahead market *operating reserve offer* multiplied by the day-ahead market *operating reserve* schedule for each *class r reserve* [operating profit function] (Variants A, B and C) o The difference between day-ahead market price and the *market participant's* day-ahead market *offer* multiplied by the day-ahead market schedule up to the *minimum loading point* for

Market Rule Section [Chapter. No.] [Section no.]	**Type**	**Topic**	**Requirement**
			the *minimum generation block run time* [operating profit function] (Variant B); and o Start-up offer incurred to bring an offline *generation unit* through all the unit specific start-up procedures, including synchronization and ramp up to *minimum loading point*. The start-up offer is calculated based on three scenarios: (1) *minimum loading point* is reached within the first six intervals of the first hour, (2) *minimum loading point* is reached between intervals seven and 18 of the first hour, and (3) *minimum loading point* is reached after interval 18 of the first hour (Variant A). o Less: Any Day-Ahead Market Make-Whole Payment *settlement amounts* received for the same hour(s) for the day-ahead market commitment period (Variants A, B and C). o Note: The speed no-load offer will only be included in the first term (i.e. the first bullet) for intervals where the *generation unit* is injecting. • For a *pseudo-unit*: o The formulation will be the same as a not a *quick start facility* with the following differences: ▪ For a combustion turbine associated with a *pseudo-unit*, the Derived Interval Price Curve is used for the day-ahead market *offer*. The speed no-load is adjusted for the combustion turbine portion (100% less the steam turbine potion of *energy* from daily *dispatch data*); and ▪ For a steam turbine associated with a *pseudo-unit*, the Derived Interval Price Curve is used for the day-ahead market *offer* and the Derived Interval Guarantee Quantity is used for the day-ahead market schedule. The speed no-load offer and the start-up offer are adjusted for the steam turbine portion (the steam turbine potion of *energy* from daily *dispatch data*).

Market Rule Section [Chapter. No.] [Section no.]	**Type**	**Topic**	**Requirement**
			• The Variants A, B and C are based on the operation of the not a quick start *generation unit* in the day-ahead market as follows: o Variant A: The not a quick start *generation unit* has a start in the current day-ahead market *dispatch day* or was offline in HE1 of the current day-ahead market *dispatch day*. o Variant B: The not a quick start *generation unit* is scheduled in the previous day-ahead market *dispatch day* to complete to complete its *minimum generation block run time* in the current day-ahead market *dispatch day*. o Variant C: The non-quick start *generation unit* is scheduled in the current day-ahead market *dispatch day* after completing its *minimum generation block run time* in the hour ending 24 of the previous day-ahead market *dispatch day*. It also includes hours that are scheduled continuously after hours that fall under Variant B. • The Day-Ahead Generator Offer Guarantee (and the Day-Ahead Market Make-Whole Payments) will be recovered from *market participants* through: o the "Day-Ahead Market Make-Whole Payment Uplift"; and o the "Day-Ahead Market Reliability Scheduling Uplift". • The "Day-Ahead Market Make-Whole Payment Uplift": o Does not include the Day-Ahead Market Make-Whole Payments made to imports and the Day-Ahead Market Generator Offer Guarantee payments to not a *quick start facility* scheduled in the *reliability* scheduling pass of the DAM Calculation Engine; and is o Allocated on a pro-rata basis to all *real-time market* loads and exports on a daily basis. • The "Day-Ahead Market Reliability Scheduling Uplift": o Includes the Day-Ahead Market Make-Whole Payments made to imports and the Day-Ahead Market Generator Offer Guarantee payments to a not a *quick start facility* scheduled in the *reliability* scheduling pass of the Day-Ahead Market Calculation Engine. o Is allocated as follows:

Market Rule Section [Chapter. No.] [Section no.]	**Type**	**Topic**	**Requirement**
			▪ First step: Allocated on a pro-rata basis across virtual transactions. ▪ Second step: The remainder will be allocated on a pro-rata basis to all *real-time market* loads and exports on a daily basis.
Chapter 9, Section 4A.X	New	Real-Time Generator Offer Guarantee	This new section sets out the *market rules* around the determination of the Real-Time Generator Offer Guarantee. • This section will include the eligibility criteria as follows: o *Facility*/transaction types: non-quick start *generation facility*. o *Minimum loading point* greater than zero (0) MW. o *Minimum generation block run time* greater than one hour. o *Elapsed time to dispatch* greater than one hour. • Eligibility criteria for the recovery of start-up offer: o The *generation unit* must synchronize prior to the start of their *minimum generation block run time*, unless instructed by the *IESO* not to synchronize; o The pre-dispatch commitment period does not immediately follow another commitment period where a start-up cost is guaranteed; o The pre-dispatch commitment period is in advance of a day-ahead market commitment period or a *reliability* commitment for a period shorter than its *minimum generation run down time* added to its hot *minimum generation block down time* (Note: In this case, the incremental start-up offer above the day-ahead market start-up offer will be eligible for recovery); o The pre-dispatch commitment period is in advance of a day-ahead market commitment period or a *reliability* commitment for a period longer than its *minimum generation block run time* added to its hot *minimum generation block down time*; and o The *generation unit* must complete its entire *minimum generation block run time*, unless the *IESO* dispatches the unit down for *reliability* reasons.

Market Rule Section [Chapter. No.] [Section no.]	**Type**	**Topic**	**Requirement**
			• Eligibility criteria for the recovery of start-up offer for a combustion turbine associated to a *pseudo-unit*: o The combustion turbine must synchronize prior to the start of their *minimum generation block run time*, unless instructed by the *IESO* not to synchronize; o The pre-dispatch commitment period does not immediately follow another commitment period where a start-up cost is guaranteed; o The pre-dispatch commitment period is in advance of a day-ahead market commitment period or a *reliability* commitment for a period shorter than its *minimum generation run down time* added to its hot *minimum generation block down time* (Note: In this case, the incremental start-up offer above the day-ahead market or *reliability* start-up offer will be eligible for recovery); and o The pre-dispatch commitment period is in advance of a day-ahead market commitment period for a period longer than its *minimum generation block run time* added to its hot *minimum generation block down time*; and o The *generation unit* must complete its entire *minimum generation block run time*, unless the *IESO* dispatches the unit down for *reliability* reasons. • Eligibility criteria for the recovery of start-up offer for a steam turbine associated to a *pseudo-unit*: o At least one of the combustion turbines associated with the *pseudo-unit* has met all of its eligibility criteria; and o The simple cycle flag of the combustion turbine(s) associated with the *pseudo-unit* is not activated. • Mode of operation: o Where a *pseudo-unit* has a *pre-dispatch* commitment but operates in single cycle mode in the *real-time market* due to a failure or outage at the associated steam turbine, the Real-Time Generator Offer Guarantee for the steam turbine will be calculated as the same for a failure or outage as a not a quick start *generation unit*.

Market Rule Section [Chapter. No.] [Section no.]	Type	Topic	Requirement
			o For a combustion turbine associated to *pseudo-unit* that changes to single cycle mode commitment as part of a *pseudo-unit*, the Real-Time Generator Offer Guarantee for the combustion turbine will be calculated using the *offer* prior to the change to single cycle mode. • This section will include the formulation of the Real-Time Generator Offer Guarantee as the sum of the following: o The maximum of (1) the difference between *real-time market* price and the *market participant's real-time market energy offer* multiplied by the *real-time market* schedule [operating profit function] and (2) the difference between *real-time market* price and the *market participant's real-time market energy offer* multiplied by the actual injection [operating profit function] added to the *pre-dispatch* speed no-load offer plus any revenue earned (the day-ahead market price multiplied by the day-ahead market schedule) during the ramp up period less any revenue earned (*real-time market* price multiplied by the actual injection) during the ramp up period. (Variants A, B and C); o The difference between the *real-time market operating reserve* prices and the *market participant's real-time market operating reserve offer* multiplied by the *real-time market operating reserve* schedule for each *class r reserve* [operating profit function] (Variants A, B and C); o The difference between *real-time market* price and the *market participant's real-time market offer* multiplied by the *real-time market* schedule up to the *minimum loading point* for the *minimum generation block run time* [operating profit function] added to the *pre-dispatch* speed no-load (Variant C); and o Start-up offer incurred to bring an offline *generation unit* through all the unit specific start-up procedures, including synchronization and ramp up to *minimum loading point*. The start-up offer is calculated based on three scenarios: (1) *minimum loading point* is reached within the first six intervals of the first hour, (2) *minimum loading point* is reached between

Market Rule Section [Chapter. No.] [Section no.]	**Type**	**Topic**	**Requirement**
			intervals seven and 18 of the first hour, and (3) *minimum loading point* is reached after interval 18 of the first hour. Subject to: ▪ Where the commitment is a stand-alone pre-dispatch commitment or when the commitment is in advance of a pre-existing day-ahead market commitment for longer than its *minimum generation block run time* added to its hot *minimum generation block down time*, then the pre-dispatch start-up offer is used or when the commitment is in advance of a pre-existing day-ahead market commitment for shorter than its *minimum generation block run time* added to its hot *minimum generation block down time*, then incremental portion of the pre-dispatch start-up *offer* above the *day-ahead* start-up offer is used (Variants A and C); and ▪ Where the pre-dispatch commitment immediately follows another commitment, then the start-up offer is set to zero (Variant B). o Less: Any Real-Time Make-Whole Payment *settlement amounts* received for the same hour(s) for the day-ahead market commitment period (Variants A, B and C). Note: The speed no-load offer will only be included in the first term (i.e. the first bullet) for intervals where the *generation unit* is injecting. • For a *pseudo-unit*: o The formulation will be the same as a non-quick start *generation unit* with the following differences: ▪ For a combustion turbine associated with a *pseudo-unit*, the Derived Interval Price Curve is used for the *real-time market offer*. The speed no-load is adjusted for the combustion turbine portion (100% less the steam turbine potion of *energy* from daily *dispatch data*); and ▪ For a steam turbine associated with a *pseudo-unit*, the Derived Interval Price

Market Rule Section [Chapter. No.] [Section no.]	**Type**	**Topic**	**Requirement**
			Curve is used for the *real-time market offer* and the Derived Interval Guarantee Quantity is used for the *real-time market* schedule. The speed no-load offer and the start-up offer are adjusted for the steam turbine portion (the steam turbine potion of *energy* from daily *dispatch data)*. For the first term (i.e. the first bullet) in the formulation, the operating profit for the actual injection above *minimum loading point* is not included. ▪ Note: The calculation period for a steam turbine associated with a *pseudo-unit* is the set of continuous hours where at least one of its associated *pseudo-units* is committed in *pre-dispatch*. The calculation period includes any ramp up intervals directly associated with an included *pre-dispatch* commitment. • The Variants A, B and C are based on the operation of the non-quick start *generation unit* in the *real-time market* as follows: o Variant A: The non-quick start *generation unit* has a *pre-dispatch* commitment independently or in advance of a day-ahead market commitment, and the *pre-dispatch* commitment does not cross over midnight to complete its *minimum generation block run time*. o Variant B: The non-quick start *generation unit* has a pre-dispatch commitment immediately following a day-ahead market commitment or a *reliability* commitment under which the start-up offer is already considered. o Variant C: The non-quick start *generation unit* has a pre-dispatch commitment independently or in advance of a day-ahead market commitment, and the *pre-dispatch* commitment crosses over midnight to complete its *minimum generation block run time*. • The Real-Time Generator Offer Guarantee will be recovered from *market participants* through the “Real-Time Generator Offer Guarantee Uplift”. The “Real-Time Generator Offer Guarantee Uplift” will be

Market Rule Section [Chapter. No.] [Section no.]	**Type**	**Topic**	**Requirement**
			allocated on a pro-rata basis to all *real-time market* loads and exports on a daily basis. Overlap: Market Power Mitigation detailed design document
Chapter 9, Section 4A.X	New	Real-Time Ramp-Down Settlement Amount	This new section sets out the *market rules* around the determination of the Real-Time Ramp-Down Settlement Amount. • Eligibility criteria: o *Facility*/transaction type: Non-quick start *generation facility* • Eligibility criteria for the calculation for a steam turbine associated to a *pseudo-unit*. o The steam turbine is ramping down from its 1x1 *minimum loading point* to come offline; o If only one associated combustion turbine is online prior to and during the ramp-down of the steam turbine, then the calculation will use the *offers* for the *pseudo-unit* associated with that combustion turbine; and o If there is more than one associated combustion turbine ramping down during the ramp-down of the steam turbine, then the calculation will use the *offer* for the *pseudo-unit* associated with the last combustion turbine to drop below its *minimum loading point*. • The section will include the formulation of the Real-Time Ramp-Down Settlement Amount as follows: o If the *generation unit* is coming offline during a day-ahead market scheduled period, then the sum of: ▪ The difference between the day-ahead market price and the *real-time market energy offer* multiplied by the actual injection [operating profit function]; and ▪ The difference between the day-ahead market price and the day-ahead market *offer* multiplied by the actual injection [operating profit function]. o Otherwise: ▪ The difference between the *real-time market* and the *real-time market*

Market Rule Section [Chapter. No.] [Section no.]	**Type**	**Topic**	**Requirement**
			energy offer multiplied by the actual injection [operating profit function]. o Note: The *real-time market energy offer* is the *energy offer* in the hour immediately before the hour in which ramp-down begins, where price is adjusted by a ramp-down factor. • For a *pseudo-unit*: o The formulation will be the same as a non-quick start *generation unit*. • The Real-Time Ramp-Down Settlement Amount will be recovered from *market participants* through the "Real-Time Ramp-Down Settlement Amount Uplift". The "Real-Time Ramp-Down Settlement Amount Uplift" will be allocated on a pro-rata basis to all *real-time market* loads and exports on a daily basis.
Chapter 9, Section 4A.X	New	Congestion Rent and Loss Residuals	This new section sets out the *market rules* around the determination of the Congestion Rent and Loss Residuals. • This section will include the formulation of the Congestion Rent and Loss Residuals as the sum of the following: o The sum of: (1) the difference between the day-ahead market schedules (injection versus withdrawal) multiplied by the day-ahead market price; and (2) the difference between the actual injection and withdrawal in real-time versus the difference between the day-ahead market schedules (injection versus withdrawal) multiplied by the *real-time market* price for *generation facilities*, *dispatchable loads*, and price responsive loads; o The difference between the day-ahead market schedules (injection versus withdrawal) multiplied by the difference between the day-ahead market price and the *real-time market* price for virtual transactions; o The actual withdrawal multiplied by the sum of the day-ahead market price and the load forecast deviation charge for *non-dispatchable loads*; o The difference between the day-ahead market schedules (injection versus withdrawal) multiplied by the day-ahead market price, added to the difference between the scheduled quantities for *energy* in real-time (injection and withdrawal) minus the difference between the

Market Rule Section [Chapter. No.] [Section no.]	**Type**	**Topic**	**Requirement**
			day-ahead market schedules (injection versus withdrawal) multiplied by the *intertie* scheduling price for *boundary entities*; and o Less: The sum of: the difference between the day-ahead market schedules (injection versus withdrawal) multiplied by the day-ahead market price, added to the difference between the scheduled quantities for *energy* in real-time (injection and withdrawal) minus the difference between the day-ahead market schedules (injection versus withdrawal) multiplied by the *intertie congestion price* for *boundary entities*. • The Congestion Rent and Loss Residuals Disbursement will be allocated on a pro-rata basis to all *real-time market* loads on a monthly basis.
Chapter 9, Section 4A.X	New	Generator Failure Charge – Guarantee Cost Component	This new section sets out the *market rules* around the determination of the Generator Failure Charge – Guarantee Cost Component. • Eligible *facility*/transaction types: *generation facility* • Exception requirements: The generation failure charge will not be applied when a failure to meet the *pre-dispatch* commitment is outside the *market participant's* control. The reasons include: o Forced outages (out of the *market participant's* control), transmission outages, force majeure, dispatched down by the *IESO* for *reliability* reason, and *reliability* commitments. • The Generator Failure Charge – Guarantee Cost Component will be assessed when one of the following three scenarios occurs and does not fall under the exception requirement above: o Failure to ramp to *minimum loading point* on schedule; o Failure to operate until the end of its commitment period. This includes hours when the *generation unit* is extended in *pre-dispatch* beyond its initial commitment; and o Failure to operate for any hours (i.e. failure to come online). o Note: For each type of failure, the failure intervals (i.e. period subject to the failure charge assessment) will be defined in the *market rules*.

Market Rule Section [Chapter. No.] [Section no.]	**Type**	**Topic**	**Requirement**
			o Note: If there are multiple isolated failures in a *dispatch day*, each failure will be assessed separately. • For a combustion turbine associated to a *pseudo-unit*, the Generator Failure Charge – Guarantee Cost Component will be assessed when one of the following scenarios occurs and does not fall under the exception requirement above: o Failure to ramp to *minimum loading point* on schedule; o Failure to operate until the end of its commitment period of its associated *pseudo-unit*. This includes hours when the *generation unit* is extended in *pre-dispatch* beyond its initial commitment; o Failure to operate for any hours (i.e. failure to come online); and o The associated *pseudo-unit* activated its single cycles flag at any time during its commitment period or an extension of its commitment period and the units has increased its price. o Note: For each type of failure, the failure intervals (i.e. period subject to the failure charge assessment) will be defined in the *market rules*. • For a steam turbine associated to a *pseudo-unit*, the Generator Failure Charge – Guarantee Cost Component will be assessed when one of the following scenarios occurs and does not fall under the exception requirement above: o Failure to ramp to *minimum loading point* on schedule by one of its associated combustion turbines; o Failure to operate until the end of its commitment period by one or more of its associated combustion turbines. This includes hours when the *generation unit* is extended in *pre-dispatch* beyond its initial commitment; o Failure to operate for any hours (i.e. failure to come online) by one or more of its associated combustion turbines; and o The associated *pseudo-unit(s)* activated its (their) single cycles flag(s) at any time during

Market Rule Section [Chapter. No.] [Section no.]	**Type**	**Topic**	**Requirement**
			its commitment period or an extension of its commitment period. o Note: For each type of failure, the failure intervals (i.e. period subject to the failure charge assessment) will be defined in the *market rules*. • This section will include the formulation of the Generator Failure Charge – Guarantee Cost Component as follows: o The prorated factor multiplied by the incremental start-up offer plus the pre-dispatch speed no-load minus the difference between the pre-dispatch price and the pre-dispatch *offer* for the *pre-dispatch schedule* [operating profit function] multiplied by the schedule factor. Where: o Incremental start-up offer: ▪ If the *pre-dispatch* commitment connects with a day-ahead commitment and pre-dispatch advancement hours is less than the *minimum generation block run time* plus *minimum generation block down time*, then the incremental start-up offer is the difference between the *pre-dispatch* and day-ahead market start-up offers. ▪ Otherwise the incremental start-up offer is equal to the pre-dispatch start-up offer. o Prorated factor: ▪ Minimum of 1, or the number of intervals where the actual injection is less than the *minimum loading* point divided by the *minimum generation block run time* that is part of the *pre-dispatch commitment* failure that does not overlap with a day-ahead market commitment. o Schedule factor: ▪ 1 minus the maximum of the actual injection and the day-ahead market schedule divided by the *pre-dispatch schedule*.

Market Rule Section [Chapter. No.] [Section no.]	**Type**	**Topic**	**Requirement**
			• For a *pseudo-unit*: o For a combustion turbine associated to a *pseudo*-unit, the formulation will be the same as a non-quick start *generation unit* with the following differences: ▪ The Derived Interval Price Curve is used for the pre-dispatch *offer*; and ▪ The incremental start-up offer and the pre-dispatch speed no-load are adjusted for the combustion turbine portion (1 minus the steam turbine portion). o For a steam turbine associated to a *pseudo*-unit, the formulation will be the same as a non-quick start *generation unit* with the following differences: ▪ The Derived Interval Price Curve for the Generator Failure Charge – Guarantee Cost Component is used for the pre-dispatch *offer*; ▪ The Derived Interval Guarantee Quantity for the Generator Failure Charge – Guarantee Cost Component is used for the *pre-dispatch schedule*; and ▪ The incremental start-up offer and the pre-dispatch speed no-load are adjusted for the steam turbine portion. ▪ Note: The pre-dispatch speed no-load is the set of all combustion turbines have a failure in the same interval. ▪ Note: The steam turbine portion of the *real-time market* schedule is the sum of the steam turbines portions of the *pseudo-units* whose associated combustion turbines does not have a failure for the same interval. ▪ Note: The steam turbine portion of the *pre-dispatch schedule* is the sum of the steam turbine portions for *pseudo-units* that a pre-dispatch commitment and whose associated combustion turbines has a failure in the same interval. The pre-dispatch run that issued the most recent binding start-up

Market Rule Section [Chapter. No.] [Section no.]	**Type**	**Topic**	**Requirement**
			instruction or commitment extension for the interval is used. • The Generator Failure Charge – Guarantee Cost Component will be reimbursed to *market participants* through the “Generator Failure Charge – Guarantee Cost Component Uplift”. The “Generator Failure Charge – Guarantee Cost Component Uplift” will be allocated on a pro-rata basis to all *real-time market* loads and exports on a daily basis.
Chapter 9, Section 5	Existing - requires amendment	Market Power Mitigation	This sections sets out the *market rules* around the *settlement* of the Market Power Mitigation. New Section 5.2 – Reference Level Settlement Charge • Eligible *facility*/transaction type: *Generation facility* (duel fuel resources only) • Process: o The *IESO* will perform the conduct test using the lower reference level. o Pass – no adjustment required. o Fail – the *IESO* will conduct the two additional tests: ▪ Test 1: The make-whole payment impact test is calculated using the lower reference level. If the test fails, the Day-Ahead Market Make-Whole Payment and the Real-Time Make-Whole Payment will be adjusted (refer to Section 3B.X). ▪ Test 2: If the location marginal price falls between the higher reference level and the lower reference level, the Reference Level Settlement Charge will be calculated. • The Reference Level Settlement Charge will be adjusted by a persistence multiplier. The persistence multiplier (P) is determined as follows: o P = 1 when first instance is within an 18-month period. o P = 2 when second instance is within 18 months of the last substantially similar conduct.

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<tr><th>Market Rule Section
[Chapter. No.] [Section no.]</th><th>Type</th><th>Topic</th><th>Requirement</th></tr>
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P = 3 when third or additional instances within 18 months of the last instance of substantially similar conduct.

Note: The market rules around the persistence multiplier may (instead) be included in New Appendix 7.8 – Market Power Mitigation.
The section will include the formulation for a day-ahead market transaction as follows:
The difference between the day-ahead market price and the day-ahead reference level based on a lower fuel cost multiplied by the day-ahead quantity [operating profit function] and adjusted by the persistence multiplier.
The section will include the formulation for pre-dispatch or real-time market transaction as follows:
The difference between the real-time market price and the real-time reference level based on a lower fuel cost multiplied by the actual injection [operating profit function] and adjusted by the persistence multiplier.
The Reference Level Settlement Charge will be reimbursed to market participants through the “Reference Level Settlement Charge Uplift”. The “Reference Level Settlement Charge Uplift” will be allocated on a pro-rata basis to all real-time market loads and exports on an hourly basis.
New Section 5.3 – Ex-Post Mitigation Settlement Charges
This new section will include the market rules (or will include references to new Chapter 7, Appendix 7.8, Section 5 – see Market Power Mitigation Chapter) required for the following two new ex-post mitigation settlement charges:
Ex-Post Mitigation for Physical Withholding Settlement Charge; and
Ex-Post Mitigation for Economic Withholding on Uncompetitive Interties Settlement Charge.
The Ex-Post Mitigation Settlement Charges will be reimbursed to market participants through the “Ex-Post Mitigation Settlement Charges Uplift”. The “Ex-Post Mitigation Settlement Charges Uplift” will
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Market Rule Section [Chapter. No.] [Section no.]	**Type**	**Topic**	**Requirement**
			be allocated on a pro-rata basis to all *real-time market* loads and exports on a monthly basis. Note: Sections 5.2 and 5.3 (in their entirety or part of) may be moved to Sections 3B and 4A, respectively (TBD). Overlap: Market Power Mitigation detailed design document
Chapter 9, Section 6	Existing - no change	Settlement Statements	This section sets out the *market rules* around *settlement statements* and *invoices*, including but not limited to processes, coverage, timing, and the responsibilities of *market participants* and of the *IESO*. • Provisions for the following sections unaffected by design changes specified in the Market Settlement detailed design document: o Section 6.4 – Settlement Statement Process o Section 6.8 – Settlement Statement Recalculations o Section 6.11 – Payment of Invoices o Section 6.12 – Funds Transfer o Section 6.15 – Payment Errors, Adjustments, and Interest Overlap: Market Billing and Funds Administration and Prudential Security detailed design documents
Chapter 9, Section 6	Existing - requires amendment	Settlement Statements	This section sets out the *market rules* around *settlement statements* and *invoices*, including but not limited to processes, coverage, timing, and the responsibilities of *market participants* and of the *IESO*. Section 6.1 – Communication of Settlement Information • As a matter of clean-up, the term “facsimile” can be removed from Section 6.1.2. Section 6.2 - Settlement Schedule and Payments Calendar: • As a matter of clean-up, may need to remove all references to the term *market commencement date*, specifically in sections 6.2.1 and 6.2.4. • Sections 6.2.1.2, 6.2.1.6, and 6.2.1.8 – These sections need to be expanded to include the day-ahead market. Section 6.3 – Settlement Cycles • The heading prior to Section 6.3.9 will be revised from “Real-Time Markets” to “Day-Ahead Markets and Real-time Markets”. • Sections 6.3.9, 6.3.11, 6.3.14, 6.3.15, 6.3.16, and 6.3.17 will be expanded to include the day-ahead market.

Market Rule Section [Chapter. No.] [Section no.]	**Type**	**Topic**	**Requirement**
			• Section 6.3.10A (day-ahead commitment process related) will be deleted as it is no longer required under MRP. • May need to update timelines and remove all references to the term *market commencement date*, specifically in sections 6.3.18 and 6.3.19. Section 6.5 – Preliminary Statement Coverage • Sections 6.5.1.2 and 6.5.2A need to be expanded to include the day-ahead market. • Section 6.5.2 needs to be revised to delete Section 6.5.2.3 (the *hourly Ontario energy price* in that *settlement hour*). This section also needs to be amended to include day-ahead market prices. • Sections 6.5.3.1 and 6.5.3.2 need to be revised to remove a. "the market schedule". • As a matter of clean-up, this section may be renamed from "Preliminary Statement Coverage" to "Preliminary Settlement Statement Coverage". Section 6.6 – Validation of Preliminary Settlement Statement • Section 6.6.11 needs to be revised as follows: o Sections 6.6.11.1 (the 5-minute *energy market* price), 6.6.11.2 (the 5-minute price for any class of *operating reserve*), and 6.6.11.4 (the *hourly Ontario energy price*) need to be deleted. o New Section 6.6.11.5 for locational marginal prices for any *dispatch interval* in a given *settlement hour*. o New Section 6.6.11.6 for the Ontario zonal prices for *energy* for a given *settlement hour*. o Section 6.6.11 (last paragraph) needs to be revised from "…elements noted in sections 6.6.11.1 to 6.6.11.4" to "…elements noted in sections 6.6.11.1 to 6.6.11.6" to include the new sections outside of the *notice of disagreement* process. Section 6.7 – Final Settlement Statement Coverage • Section 6.7.1.2 needs to be expanded to include the day-ahead market. • As a matter of clean-up, sections 6.7.5 through 6.7.7 may be moved to a new Section 6.7A called "Validation of Final Settlement Statement" to align with Sections 6.5

Market Rule Section [Chapter. No.] [Section no.]	Type	Topic	Requirement
			and 6.6 (Preliminary Statement Coverage and Validation of Preliminary Settlement Statement, respectively). Section 6.9 – Responsibility of the IESO • Section 6.9.2 needs to be expanded to include the day-ahead market. Section 6.10 – Settlement Invoices: • Section 6.10 – This section needs to be expanded to include the day-ahead market. • Add new Section 6.10.1.3: The *invoice* will include *settlement amounts* from the first *settlement* and the second *settlement*. Overlap: Market Billing and Funds Administration detailed design document Section 6.13 – Confirmation Notices • As a matter of clean-up, this section may need to be updated by replacing the following in section: "At the end of each calendar month…" to "After the end of each calendar month…" to line up with the market manual (Market Manual 5.9 – Settlement Payment Methods and Schedule). The market manual states that the *monthly confirmation notice* is sent out on the first *business day* after the end of the calendar month. Section 6.14 – Payment Default • Section 6.14.7 and 6.14.8 – This section needs to be expanded to include day-ahead market, *market creditors*. • As a matter of clean up, the term "*real-time market creditor(s)*" will be revised to "*real-time market*, *market creditor(s)*" in Sections 6.14.7 and 6.14.8. Overlap: Prudential Security detailed design document Section 6.16 – Settlement Financial Balance/Maximum Amount Payable by IESO: • Sections 6.16.1.1 and 6.16.1.2: These sections will need to extend the *IESO* financial neutrality restrictions to include day-ahead market *settlement amounts*. • Section 6.16.2: This section needs to be expanded to include the day-ahead market. Overlap: Market Billing and Funds Administration detailed design document Section 6.17 – Audit • May need to update section to remove reference to the term *market commencement date* and replace

Market Rule Section [Chapter. No.] [Section no.]	**Type**	**Topic**	**Requirement**
			with a new term ("market renewal program implementation date" (TBD)), specifically Section 6.17.3.
Appendix 9.1	Existing - no change	VEE Process	This section sets out the *market rules* around the validation, estimation and editing of *metering data*. • Provisions unaffected by the design changes specified in the Market Settlement detailed design document. Overlap: Revenue Meter Registration detailed design document
Appendix 9.2	Existing - no change	[Intentionally left blank]	• Section previously deleted, no change required.

End of Section –

5 Procedural Requirements

5.1 Market-Facing Procedural Impacts

The existing *market manuals*, format specifications, reports, forms and training guides related to Market Settlement will be retained to the extent possible. The majority of changes result from the introduction of a day-ahead market, the two *settlement* process and locational marginal pricing within the future day-ahead and *real-time market*. For the purposes of this document, all new market-facing procedures are described in terms of modification to existing documents in Section 5.1. The documents most directly related to Market Settlement are:

Market Manuals:

- IESO Charge Types and Equations;
- Market Manual 5: Settlements, Part 5.0 - Settlements Overview;
- Market Manual 5: Settlements, Part 5.1 – Settlement Schedule and Payments Calendars (SSPCs);
- Market Manual 5: Settlements, Part 5.3 – Submission of Physical Bilateral Contract Data;
- Market Manual 5: Settlements, Part 5.5 – Physical Markets Settlement Statements;
- Market Manual 5: Settlements, Part 5.7 – Financial Markets Settlement Statements;
- List of Resources for Physical Bilateral Contracts;
- Market Manual 4: Market Operations, Part 4.6 – Real-Time Generation Cost Guarantee Program;
- Market Manual 6: Participant Technical Reference Manual; and
- Market Manual 9: Day-Ahead Commitment Process, Part 9.5 – Settlement for the Day-Ahead Commitment Process.

Format Specifications:

- Format Specifications for Settlement Statement Files and Data Files;
- File Format Specifications for Participant Transmission Tariff Data Files;
- File Format Specifications for the Transmitter Transmission Tariff Data File;
- File Format Specifications for Transmitter Reconciliation Data File; and
- Transmission Tariff Peak System Demand Data Report.

Training Material:

- Guide to Settlement Claims and Data Submissions via Online IESO; and
- Settlement Statements and Invoices.

Table 5-1 identifies sections within the *market manuals*, format specifications, reports, forms and training materials that will not require changes, will require modifications and new sections that will need to be added to support the *settlement process* in the future market.

Table 5-1: Impacts to Market-Facing Procedures

Procedure	Type of change (no change, modification, new)	Section	Description
List IMP_LST_0001 IESO Charge Types and Equations	Modification	1.6 How This Document is Organized	• Delete reference to Section 2.6.
		2.1 Variable Descriptions	• Update for new, modified and disposed of variables.
		2.2 Charge Types and Equations	• Update for new, modified and disposed of *charge types* • *IESO* will consult with CRA for tax treatment of new and modified *charge types*
		2.3 Rounding Conventions - by Settlement Variable	• Update for new, modified and disposed of variables.
		2.4 Rounding Conventions - by Charge Type	• Update for new, modified and disposed of *charge types.*
		2.5 Settlement of Physical Bilateral Contracts	• Update to include *settlement* of DAM *physical bilateral contracts.*
		2.6 Exemptions from the Day-Ahead Import Failure Charge, Day-Ahead Export Failure Charge, and Day-Ahead Linked Wheel Failure Charge	• Delete section. Not required under MRP.
List IMP_LST_0001 IESO Charge Types and Equations	No Change	1.1 Purpose 1.2 Scope 1.3 Tax Treatment	• No changes required to these sections.

Procedure	Type of change (no change, modification, new)	Section	Description
		1.4 Who Should Use This Document 1.5 Conventions	
Market Manual: MDP_MAN_0005 Market Manual 5: Settlements, Part 5.0 - Settlements Overview	Modification	2 About This Manual	• Add new sub-section to provide overview of two-*settlement* system, DAM physical and DAM virtual transactions.
		2.2 Scope	• Include *market participants* transacting in virtual transactions. • Define *physical markets* to include *real-time market* and day-ahead market. • Revise reference to "*transmission rights* market" to "DAM *transmission rights* market" (DAM TRs).
		2.3 Who Should Use This Manual	• Include *market participants* participating in the Day-Ahead Market and *market participants* transacting in virtual transactions.
		3.2 About the Procedures in This Manual	• Update to include day-ahead *energy* and *operating reserves markets.* • Update reference to *transmission rights* market to DAM *transmission rights* market.
		4 Applicability of Procedures	• Update Table 4-1 to incorporate new/modified events and procedures addressed in each Market Manual 5 series.
Market Manual: MDP_PRO_0031 Market Manual 5: Settlements, Part 5.1 - Settlement Schedule and Payments Calendars (SSPCs)	Modification	1.3 Overview of the Interconnection Agreements (SSPCs)	• Preface all references to *transmission rights* and *TR auction* with DAM • Update all references to *real-time market* to include day-ahead market (physical, virtual
Market Manual: MDP_PRO_0031 Market Manual 5: Settlements, Part 5.1- Settlement Schedule and Payments Calendars (SSPCs)	No Change	2 Procedural Work Flow 3 Procedural Steps Appendix A – Forms Appendix B Example of the SSPC	• No changes required to these sections.

Procedure	Type of change (no change, modification, new)	Section	Description
Market Manual: MDP_PRO_0034 Market Manual 5: Settlements, Part 5.3 - Submission of Physical Bilateral Contract Data	Modification	1.1 Purpose	• Update to refer to *real-time market* PBC and day-ahead market PBC.
		All Sections	• Include activities related to submitting DAM PBC data • All existing content will clearly indicate as applying to either *real-time market* PBC data only, day-ahead market PBC data only or consolidated where the procedures are identical.
		New Section	• New section(s) regarding the submission of DAM PBC data will need to be added, including the procedural steps for submission of *physical bilateral contracts* • Information should include: o Context of DAM PBCs relative to real-time PBCs o Context of DAM PBCs relative to the two-*settlement* system o Financial implications o Format of DAM PBC data o Submission timelines o Procedural Work Flow o Procedural Steps o Forms o Data Requirements
Market Manual: MDP_PRO_0034 Market Manual 5: Settlements, Part 5.3 - Submission of Physical Bilateral Contract Data	No Change	Appendix A Forms Appendix B Data Requirements	• No changes required to these sections.
Market Manual: MDP_PRO_0033 Market Manual 5: Settlements, Part 5.5 - Physical Markets	Modification	1.3.1 Issuing the Preliminary Settlement Statement	• Update to state that the *preliminary settlement statements* will include *settlement amounts* from the first and second *settlement.*
		1.3.2 Interpreting the Settlement	• Include DAM physical and virtual transactions.

Procedure	Type of change (no change, modification, new)	Section	Description
Settlement Statements		Statements and Data Files	• Update references to Ontario *energy* prices to Ontario zonal price and locational marginal pricing. • Delete references to *market schedules.*
		1.3.4 Submitting a Notice of Disagreement	• Update 5-minute *energy market price* to locational marginal price • Update *hourly Ontario energy price* to Ontario zonal price • Delete references to *Administrative Prices* • Revision to Table 1–1: o include DAM *physical bilateral contracts* o remove references to *market schedules*, *schedule of record*, CMSC, DA-PCG, RT-GCG, day-ahead withdrawal o update reason codes
		1.6.5 Administrative Pricing Event	• Delete section. Not applicable in future market.
		1.6.8 Limiting CMSC Payments for Exporters and Dispatchable Loads	• Delete section. Not applicable in future market.
		1.6.9 Adjustment for Facility-Induced CMSC	• Delete section. Not applicable in future market.
		1.6.10 Real-time Import Failure Charges and Export Failure Charges	• Update to state that new future market *settlement amount* will reflect new *intertie congestion price* rules – price at the internal node equivalent to the *intertie.* • Delete all references to DACP. • Update Table 1-3 for new reason codes and delete all references to CMSC, day-ahead and *market schedules.* • Update examples to reflect new pricing and equation.
		1.6.12 CMSC Adjustment for Replacement Offer Events	• Delete section. Not applicable in future market.

Procedure	Type of change (no change, modification, new)	Section	Description
		1.6.20 Adjustment for Self-Induced CMSC Earned by Certain Facilities	• Delete section. Not applicable in future market.
		1.6.22 Limiting Payments to Exports during Negative Prices	• Update *intertie* zonal price references to *intertie settlement* price (ISP). • Replace *charge type* 100 with HPTSA. • Delete reference to *Market Manual* 9.5.
		1.6.27 Transmission Rights Clearing Account Disbursement	• Update references to *transmission rights* to DAM *transmission rights.* • *Charge type* 102 will be decommissioned in the future market. • Update to disbursement methodology to be informed by *TR Market* Review.
		1.6.28 Limiting Constrained-off CMSC to Interties	• Delete section. Not applicable in future market.
		1.6.31 Limiting Constrained On CMSC Payments to Generators Ramping Down	• Delete section. Not applicable in future market.
		2.1 Preliminary Settlement Statements	• Preamble to this section should be revised to place this procedure in the context of the two-*settlement* system.
		3 Procedural Steps All sub-sections	• Review for consequential changes as a result of various preceding changes within this document.

Procedure	Type of change (no change, modification, new)	Section	Description
Market Manual: MDP_PRO_0033 Market Manual 5: Settlements, Part 5.5 - Physical Markets Settlement Statements	New	New Sections	• New sections required for new *settlement amounts*: o First *settlement* and second *settlement* of the two-*settlement* system o DAM Make-Whole Payment o DAM Make-Whole Payment Uplift o DAM Generator Offer Guarantee o DAM Reliability Scheduling Uplift o Real-Time Make-Whole Payment o Real-Time Make-Whole Payment Uplift o Real-Time Generator Offer Guarantee o Real-Time Generator Offer Guarantee Uplift o Generator Failure Charge o Generator Failure Charge Uplift o Congestion Rent and Loss Residuals • New sections for amended *settlement amounts*: o Operating Reserve Settlement Shortfall Debit o Intertie Failure Charges o Real-Time Intertie Offer Guarantee o Replacement Energy Offers Program
Market Manual: MDP_PRO_0046 Market Manual 5: Settlements, Part 5.7 - Financial Markets Settlement Statements	Modification	1.1 Introduction 1.2 Scope	• Preface all references to *transmission rights* market, *TR auction* with DAM. • Generally, this document should only describe the activities of the settling auctions for DAM Financial *Transmission Rights* (DAM FTRs).
		1.3.4 Submitting a Notice of Disagreement	• Remove references to 5-minute *energy market* price, 5-minute price for any class of *operating reserve*, and *hourly Ontario energy price* to locational marginal price and Ontario zonal price.

Procedure	Type of change (no change, modification, new)	Section	Description
Market Manual: MDP_PRO_0046 Market Manual 5: Settlements, Part 5.7 - Financial Markets Settlement Statements	No Change	3 Procedural Steps Appendix A Forms Appendix B Notice of Disagreement Screens	• No changes required to these sections.
List: IMO_PBCL_0001 List of Resources for Physical Bilateral Contracts	Modification	All Sections	• Update list to include DAM resources for *physical bilateral contracts* .
Market Manual: PRO-324 Market Manual 4 Market Operations, Part 4.6 - Real-Time Generation Cost Guarantee Program	Modification	All	• This manual will be updated or will become obsolete. Real-Time Generation Cost Guarantee replaced by Real-Time Generator Offer Guarantee.
Market Manual: IMO_MAN_0024 Market Manual 6: Participant Technical Reference Manual	Modification	Section 5.1.3	• Preface all references to *transmission rights market, TR auction* with DAM. • Update Figure to include DAM
Market Manual: IESO_MAN_0080 Market Manual 9: Day-Ahead Commitment Process, Part 9.5 - Settlement for the Day-Ahead Commitment Process	Modification	All sections	• This manual will be updated for the DAM or will become obsolete. • References to Real-Time Intertie *Offer* Guarantee and Real-Time Intertie Failure Charge to be included in *market manual* 5.5.
File Format Specification: IMP_SPEC_0005Format Specifications for Settlement	Modification	All sections	• Preface all references to *transmission rights* market, *TR auction* with DAM. • Update all references to RT and/or real-time to include DAM, unless applicable to only one market type.

Procedure	Type of change (no change, modification, new)	Section	Description
Statement Files and Data Files			• Remove all disposed of *charge types* and equations. • Add new *charge types* and equations. • Modified *charge types* and equations that have been amended. • Include virtual transactions. • Updates to reflect technical implementation of DAM (i.e. new fields required on *settlement statements*). • Update for new *dispatch* or schedule data. • Any price updates required for this specification will also need to be updated.
File Format Specification: IMP_SPEC_0006 File Format Specifications for Participant Transmission Tariff Data Files	No Change	All Sections	• This technical interface is unaffected with the implementation of MRP and subject to *OEB* transmission rate order.
File Format Specification: IMP_SPEC_0007 File Format Specifications for the Transmitter Transmission Tariff Data File	No Change	All Sections	• This technical interface is unaffected with the implementation of MRP and subject to *OEB* transmission rate order.
File Format Specification: IMP_SPEC_0008 File Format Specifications for Transmitter Reconciliation Data File	No Change	All Sections	• This technical interface is unaffected with the implementation of MRP and subject to *OEB* transmission rate order.
Report Description: IMP_REP_0016 Transmission Tariff Peak System	No Change	All Sections	• This technical interface is unaffected with the implementation of MRP and subject to *OEB* transmission rate order.

Procedure	Type of change (no change, modification, new)	Section	Description
Demand Data Report			
FORM: IESO_FORM_1001 Notice of Dispute	No Change	Form	• No changes required to this form.
FORM: IESO_FORM_1549 Administrative Pricing Event Correction	Modification	Form	• Obsolete. Not required in future market.
FORM: IESO_FORM_1438 Reduced Debt Retirement Charge (DRC) Certification	Modification	Form	• No changes required to this form.
FORM: IESO_FORM_1654 Fuel Cost Compensation (Under 'Day-Ahead Commitment')	Modification	Form	• Obsolete. Not required in future market.
FORM: IESO_FORM_1419 Application for Designation of a Facility for Generation Station Service Rebate	No Change	Form	• No changes required to this form.
FORM: IESO_FORM_1507 Declaration of Designated Consumer	No Change	Form	• No changes required to this form.
Training Materials: ONLSF_GUIDE_EXT Guide to Settlement Claims and Data Submissions via Online IESO	Modification	4.5 Renewable Energy Standard Offer Program (RESOP) – LDC & Embedded LDC 4.7 Hydroelectric Contract Initiative Program	• Update references from HOEP to Ontario zonal price

Procedure	Type of change (no change, modification, new)	Section	Description
		4.8 Feed-In Tariff Program – LDC & Embedded LDC	
		4.9 Real-Time Generation Cost Guarantee Information	• Delete section. Replaced by Real-Time Generator Offer Guarantee (RT_GOG). • All further updates will be determined by the technical implementation of the new market (i.e. to be determined if an online form will be required).
Training Materials: Settlement Statements and Invoices	Modification	1 Introduction	• Include description of DAM and two-*settlement* system.
		2 Reconciling the Markets	• Delete all references to market schedules. • Preface all transmission right references with DAM. • Update 'Charge Types' section to include new *settlement amounts* and delete current *settlement amounts* that will be retired due to MRP.
		3 Preliminary Settlement Statements and Data Files	• Update all diagrams to reflect future market *settlement amounts* only.
		4 Notices of Disagreement	• Update pricing references from hourly price to Ontario zonal price and five-minute price to locational marginal pricing.
		5 Final Settlement Statements	• Update diagram to reflect future market *settlement amounts* only.
		7 Financial Markets	• Preface all transmission right references with DAM.
		8 Skill Check	• Update for relevance to future market.
		9 Additional Information	• New training material may be introduced as a result of MRP. Listing will be updated accordingly.

5.2 Internal Procedural Impacts

Some of the internal procedures currently used by the Market Settlement process will continue to have relevance in the future markets. However, many of the existing procedures will require updates for the introduction of a day-ahead market, two-*settlement* system, settlements and locational marginal pricing and their impact to some of the *settlement amounts*.

Some of the internal procedures are related to other *IESO* processes that interact with the Market Settlement process. For the most part, changes to the Market Settlement process under the MRP will not have a significant impact on other internal *manuals*. However, in some areas this may be contingent upon the tools impact of the day-ahead market. Where impact to other internal manuals does take place will be mostly in the form of data requirements from all three timeframes: DAM, PD and RT and registration data. In addition, some areas of the current procedures heavily reference relevant *market rules* and supporting tools, most of which will be undergoing changes as a result of the new day-ahead market implementation and other solution enhancements. The existing procedures will be updated to account for the corresponding changes in the *market rules* and tools. Lastly, collaboration will be required with the *OEB* to review current legislations and regulations to identify what amendments will be required as a result of MRP.

Changes or additions to internal *IESO* procedures are for internal *IESO* use as documented in Appendix B and are not included in the public version of this document. Appendix B details the impacts to internal procedures in terms of existing procedures that support the new market requirements, existing procedures that need to be updated, and new internal procedures that need to be created to support the future day-ahead market and *real-time market*

– End of Section –

6 Business Process and Information Flow Overview

6.1 Market-Facing Process Impacts

This section provides an overview to the arrangement of processes required in order to support the overall Market Settlement process and the critical information flows between them.

The context diagrams presented in Section 2 of this document are considered as level 0 data flow diagrams and represent the major flows of information into and out of the Market Settlement process. This section now presents the Market Settlement process at the next level of detail (level 1). A further break-down of the processes presented in this section (i.e. levels 2,3,4…) falls into the realm of systems design and is beyond the scope of this document.

The data flow diagram does not illustrate:

- flow of time or sequence of events (as might be illustrated in a timeline diagram);
- decision rules (as might be illustrated in Flowchart); and
- logical architecture and systems architecture (as might be illustrated in a Logical Application and Data Architecture, and/or Physical Application and Data Architecture).

What it does illustrate however, is a logical breakdown of the sub-processes that constitute a large and complex system such as the Market Settlement process. Specifically, the data flow diagram presented below illustrates:

- the Market Settlement process as a grouping of several major and tightly coupled sub-processes;
- the key information flows between each of the processes;
- external sources of key information required by the Market Settlement process;
- external destinations of key information from the Market Settlement process; and
- the same logical boundary of the Market Settlement process as illustrated in the Level 0 context diagram presented in Section 2 of this document.

This section is not meant to impart information systems or technology architecture, but rather to capture the entire Market Settlement process as a series of interrelated sub-processes.

The functional design outlined in Section 3 of this document maps to the business process overview presented in this section. In any areas where there are inconsistencies between this section and the description of the business process provided in Section 3, the business process described in Section 3 will take precedence.

The data flow diagram illustrated in Figure 6-1 presents the Market Settlement process. The following sections of this document will provide an overview to each of the main sub-processes of the Market Settlement process.

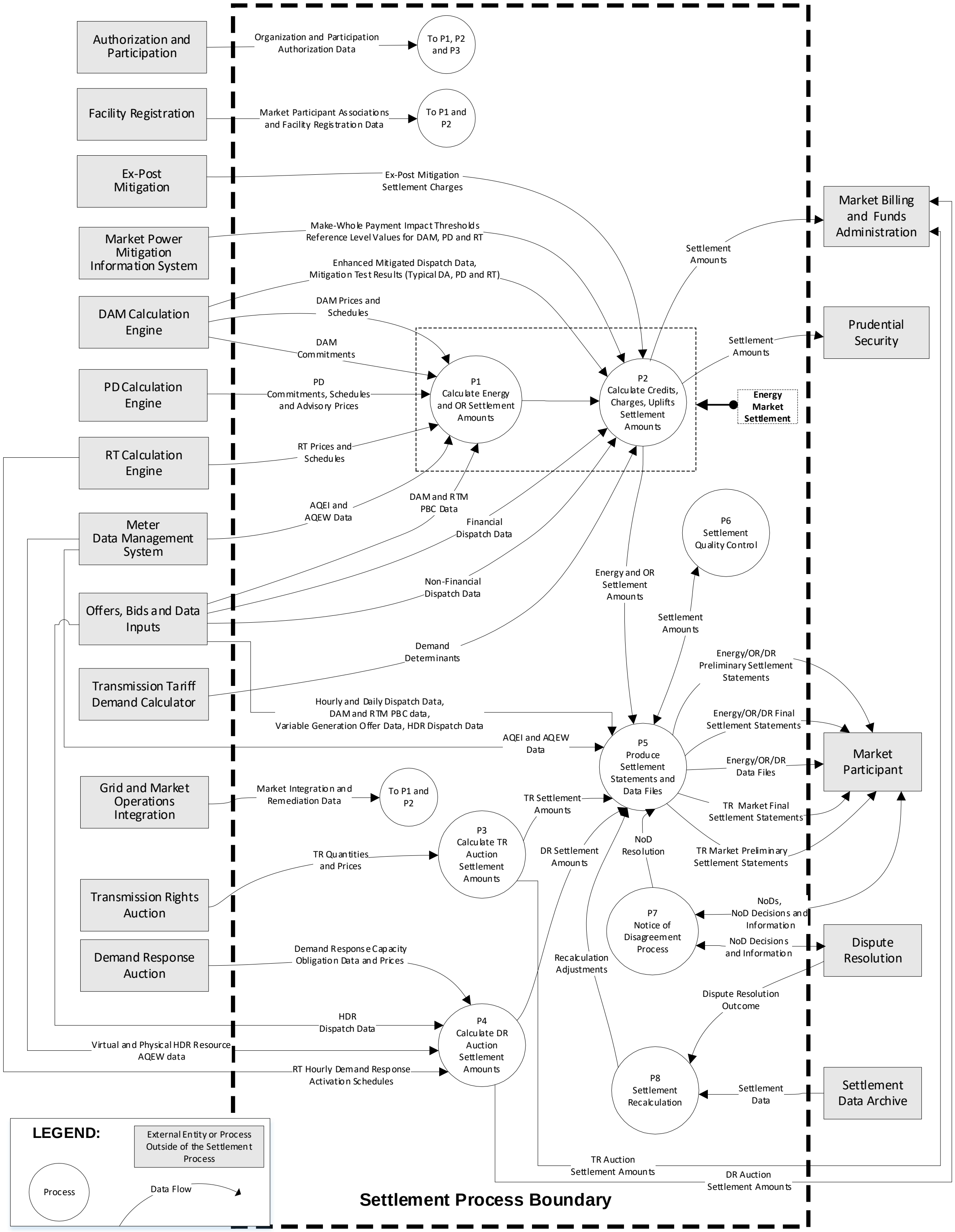

Figure 6-1: Future Settlement Process Data Flow Diagram – Level 1

6.1.1 Process P1 – Calculate Energy and OR Settlement Amounts

6.1.1.1 Description

Process P1 collects *settlement*-ready data required for the calculation of *settlement amounts* for *energy* and *operating reserve* associated with the day-ahead market and the *real-time market* and *settlement amounts* for *energy* for *non-dispatchable loads* as described in Section 3.6 of this design document. To accomplish this, this process makes use of the following information:

- Authorization and Participation data;
- Facility Registration data;
- Prices, schedules, and operational commitments produced by the DAM calculation engine, PD calculation engine, and RT calculation engine;
- Allocated quantities of *energy* injected or withdrawn from the *IESO-controlled grid*, and
- Day-ahead market and real-time *physical bilateral contract data*.

Table 6-1 summarizes the various input and output data flows for Process P1.

6.1.1.2 Input and Output Data Flows

Table 6-1: Process P1 Input and Output Data Flows

<table>
<tr><th>Flow</th><th>Source</th><th>Target Processes</th><th>Frequency</th></tr>
<tr><td>Organization and Participation Authorization Data</td><td>Authorization and Participation</td><td>Process P1</td><td>Current organization data are communicated for each trading day.</td></tr>
<tr><td colspan="4">Description:
The settlement process will utilize the following organization and participation authorization data:

Market participant name and identification number.
Current authorization for participation granting trading privileges to each market participant:

for physical transactions in the day-ahead market and the real-time market;
for physical import and export transactions in the day-ahead market and the real-time market; and
for virtual transactions in the day-ahead market.

Current authorization for each market participant:

for access to resources such as generators, dispatchable loads, non-dispatchable loads, price responsive loads, distributors, and transmitters for physical transactions;
as intertie traders for access to boundary entities for physical import and export transactions;
as virtual energy traders for access to virtual transaction zonal trading entities; and
as demand response market participants for access to the virtual hourly demand response (HDR) resources in the West, Southwest, Bruce, Niagara, Toronto, East, Ottawa, Essa, Northwest, and Northeast electrical zones.

Market participant trading privileges and authorizations will be in effect for an entire trading day. Changes to trading privileges and authorizations will start at the beginning of a trading day and end at the close of a trading day subject to advance notice requirements specified in the Facility Registration detailed design document.</td></tr>
</table>

Flow	Source	Target Processes	Frequency
Market Participant Associations and Facility Registration Data	Facility Registration	Process P1	Current *facilities* data are communicated for each *trading day*.

Description:

The *settlement process* will utilize the following *facility* registration data:

- Mutually exclusive *facility* sub-classifications: Every *delivery point* for a *registered facility* will be assigned one of the following sub-classifications:
    - Dispatchable non-quick start (NQS) *generation facility*;
    - Dispatchable *quick-start facility*;
    - Dispatchable hydroelectric *generation facility*;
    - Pump generation station – dispatchable generation resource;
    - Pump generation station – dispatchable load resource;
    - *Variable generation*;
    - *Flexible nuclear generation*;
    - *Self-scheduling generation facility*;
    - *Transitional scheduling generator*;
    - *Intermittent generator*;
    - *Dispatchable load*;
    - Price responsive load;
    - *Non-dispatchable load*;
    - Physical *hourly demand response* resource; and
    - Virtual *hourly demand response* resource.

    For details on *facility* classifications, refer to the Facility Registration detailed design document.

- Physical *facility* resource identifiers:
    - *Delivery point* will be used as the unique identifier that will be used for *settlement* of each unique *registered facility*; and
    - *Delivery point* will have a one-to-one relationship to the resource name used for submission of *dispatch data* and scheduling by the calculation engines.

    For details regarding physical *facility* resource identifiers, refer to Table 3-2 in the Facility Registration detailed design document.

- Organizational roles and responsibilities:
    - The *settlement process* will use the designated *metered market participant* assigned to each *delivery point* as the *market participant* responsible for the financial *settlement* of all quantities of physical services (including energy and operating reserve) allocated to the *delivery point*.

    For details regarding organizational roles and responsibilities refer to Table 3-1 in the Facility Registration detailed design document.

- *Market participant* associations to *boundary entities*:
  - Once authorized as an *intertie* trader, each *market participant* will be granted access to submit export *bids* for *energy* and import *offers* for *energy* and *operating reserve* for all *boundary entities*.
  - The *boundary entity* resource name and tie point ID, which is also designated as a market scheduling point (MSP) name, will uniquely identify the location of *intertie* transactions.
  - The *settlement process* will use the association of *market participant*, *boundary entity* and MSP name received from the calculation engines to uniquely identify each *intertie* transaction.
  - Refer to Market Manual Part 4.2, Appendix E for the list of existing *boundary entity* resource names and MSP names that will be used in the future day-ahead market and the *real-time market*.
- *Market participant* associations to virtual transaction zonal trading entities:
  - Once authorized as a virtual transaction energy trader, each *market participant* will be granted access to submit virtual transaction *bids* and *offers* for *energy* for all virtual transaction zonal trading entities.
  - The virtual transaction zonal trading entity resource name will uniquely identify the location of virtual transactions.
  - The *settlement process* will use the association of *market participant* and virtual transaction zonal trading entity resource name received from the DAM calculation engine to uniquely identify each virtual transaction.
  - Refer to Section 3.5.6 in the Facility Registration detailed design document for the list of virtual transaction zonal trading entities that will be used in the future day-ahead market.
- *Market participant* associations to physical and virtual *hourly demand response* resources:
  - Once authorized as a *demand response market participant*, each *market participant* will be granted access to submit HDR *dispatch data* for physical and virtual *hourly demand response* resources.
  - The *delivery point* assigned to each physical HDR resource will uniquely identify the location of physical *hourly demand response* resources.
  - Electrical zones will uniquely identify the location of virtual HDR resources. Refer to Section 3.5.2 in the Facility Registration detailed design document, for the list of electrical zones used for virtual HDR resource *bids*.
  - The *settlement process* will continue to use the *delivery point* to physical HDR resources or the association of *market participant* and electrical zone for virtual HDR resources received from the RT calculation engine to uniquely identify each *demand response capacity* delivery transaction.
- *Transmission customer* associations for every transmission tariff *delivery point* established by a *transmitter* for *transmission services*:
  - *Line connection service*;
  - *Transformation connection service*; and
  - *Network service*.
  - *Export transmission service* will be based on export transaction *energy* withdrawals.
  - The *settlement process* will continue to calculate *transmission service charges* in accordance with the terms of rate orders issued by the *OEB*.
  - Any *delivery point* can also have one or more of the following contractual identifiers associated with suppliers of *ancillary services*:
    - *Generation facility* under an *automatic generation control* (*AGC)* contract for *regulation* service;

- o *Reactive support service* and *voltage control service*; and
- o *Generation facility* under a *reliability must run contract*.

- Market price associations:
  - ▪ The *settlement process* will receive nodal prices at each *delivery point*, *boundary entity*, and virtual transaction zonal trading entity required to apply the correct price to all *settlement* calculations. The zonal locational marginal price (LMP) for the Ontario zone will be applied to the *settlement process* for *delivery points* associated with *non-dispatchable loads*.

Market participant and *facility* associations will be in effect for an entire *trading day*. Changes to such associations will start at the beginning of a *trading day* and end at the close of a *trading day* subject to advance notice requirements specified in the Facility Registration detailed design document.

Flow	Source	Target Processes	Frequency
DAM Prices and Schedules	DAM Calculation Engine	Process P1	Daily for each *dispatch hour*

Description:

This flow includes all data to be received from the DAM calculation engine, including:

- DAM prices, in $/MWh, including:
  - o Hourly LMPs for *energy* at:
    - ▪ *Intertie* metering points for imports and exports;
    - ▪ *Delivery points* for *generation facilities*, combustion turbines, steam turbines, price responsive loads and *dispatchable loads*; and
    - ▪ Virtual transaction zonal trading entities for virtual transactions.
  - o Hourly LMPs for o*perating reserve*, at:
    - ▪ *Intertie* metering points for imports and exports; and
    - ▪ *Delivery points* for *generation facilities*, combustion turbines, steam turbines and *dispatchable loads*.
  - o Hourly *intertie congestion prices* (*ICP*) at *intertie* metering points; and
  - o Hourly zonal LMP for the Ontario zone for *energy* for *non-dispatchable loads*.
- DAM schedules including:
  - o Hourly schedules for *energy* injection, in MWh, at:
    - ▪ *Intertie metering points* for imports;
    - ▪ *Delivery points* for *generation facilities*, combustion turbines, steam turbines and *pseudo-units*; and
    - ▪ Virtual transaction zonal trading entities for virtual transactions;
  - o Hourly schedules for *energy* withdrawal, in MWh, at:
    - ▪ *Intertie metering points* for exports;
    - ▪ *Delivery points* for price responsive loads and *dispatchable loads*;
    - ▪ Delivery points for *non-dispatchable loads*; and
    - ▪ Virtual transaction zonal trading entities for virtual transactions;
  - o Hourly schedules for supply of 10-minute spinning *operating reserve*, in MW, at:
    - ▪ *Delivery points* for *generation facilities*, combustion turbines, steam turbines and *dispatchable loads*; and

- o Hourly schedules for supply of 10-minute non-spinning and 30-minute *operating reserve*, in MW, at:
  - ▪ *Intertie metering points* for imports; and
  - ▪ *Delivery points* for *generation facilities*, combustion turbines, steam turbines, and *dispatchable loads*.

For detailed descriptions, attributes and usage, refer to Section 3.5.4, Table 3-10: Prices Received from the DAM Calculation Engine and Table 3-11: Schedules Received from the DAM Calculation Engine.

Flow	Source	Target Processes	Frequency
DAM Commitments	DAM Calculation engine	Process P1	Daily for each *dispatch hour*

Description:

This flow includes all DAM unit commitment data to be received from the DAM calculation engine for operational unit commitments for NQS *generation facilities*, including:

- Hourly schedules, in MWh, from the last DAM calculation engine pass prior to the *reliability* scheduling pass for *energy* injected at:
  - o *Intertie metering points* for imports; and
  - o *Delivery points* for non-quick start *generation facilities*;
- Hourly schedules, in MWh, from the *reliability* scheduling pass of the DAM calculation engine for *energy* injected at:
  - o *Intertie metering points* for imports; and
  - o *Delivery points* for NQS *generation facilities*;
- Hourly schedules, in MW, from the last DAM calculation engine pass prior to the *reliability* scheduling pass for 10-minute spinning *operating reserve* at:
  - o *Delivery points* for NQS *generation facilities*;
- Hourly schedules, in MW, from the last DAM calculation engine pass prior to the *reliability* scheduling pass for 10-minute non-spinning and 30-minute *operating reserve* at:
  - o *Delivery points* for NQS *generation facilities*; and
  - o *Intertie metering points* for imports;
- Hourly schedules, in MW, from the reliability scheduling pass of the DAM calculation engine for 10-minute spinning *operating reserve* at:
  - o *Delivery points* for non-quick start *generation facilities*;
- Hourly schedules, in MW, from the reliability scheduling pass of the DAM calculation engine for 10-minute non-spinning and 30-minute *operating reserve* at:
  - o *Delivery points* for non-quick start *generation facilities*; and
  - o *Intertie metering points* for imports.

For detailed descriptions, attributes, and usage of this data, refer to Section 3.5.4, Table 3-14: DAM Unit Commitment Events.

Flow	Source	Target Processes	Frequency
PD Commitments, Schedules, and Advisory Prices	PD Calculation engine	Process P1	Daily for each *dispatch hour*

Description:

This flow includes all data to be received from the pre-dispatch (PD) calculation engine, including:

- Advisory PD prices, in $/MWh, including:
  - Hourly pre-dispatch LMPs for *energy* at:
    - *Intertie metering points* for imports and exports;
    - *Delivery points* for NQS *generation facilities*, combustion turbines and steam turbines;
  - Hourly LMPs for *energy* for a given pre-dispatch run at:
    - *Delivery points* for NQS *generation facilities*, combustion turbines and steam turbines;
- Advisory PD schedules, in MWh, including:
  - Hourly *pre-dispatch schedules* for energy injection at *intertie metering points* for imports;
  - Hourly schedules for *energy* injection for a given pre-dispatch run at:
    - *Delivery points* for NQS *generation facilities*, *pseudo-units*, combustion turbines and steam turbines;
  - Hourly schedules for the steam turbine portion quantity for *energy* injection for a given pre-dispatch run at *delivery points* for *pseudo-units;*
  - Schedules for *energy* withdrawal at *intertie metering points* for exports;
- PD unit commitment events, including:
  - Hourly schedules, in MWh, for *energy* injected for a given pre-dispatch run at *delivery points* for NQS *generation facilities*:
  - Hourly schedules, in MW, for 10-minute spinning, 10-minute non-spinning, and 30-minute *operating reserve* for a given pre-dispatch run at *delivery points* for NQS *generation facilities*.

Note: PD timeframe prices are considered as advisory prices. The PD unit commitments received could be of the following two types:

- The "normal" PD unit commitment is made by the PD calculation engine; and
- The PD *reliability* unit commitment, which refers to a manual action taken by the control room operator (CRO). This type of unit commitment only happens when the CRO believes there is a *reliability* concern that cannot be addressed by the PD calculation engine commitment.

For detailed descriptions, attributes, and usage of this data, refer to Sec 3.5.5 Collection of Pre-Dispatch Market Data.

Flow	Source	Target Processes	Frequency
RT Prices and Schedules	RT Calculation Engine	Process P1	Daily for each *dispatch interval*

Description:

This flow includes all data to be received from the RT calculation engine, including:

- Real time prices including both LMPs and zonal prices, in $/MWh;
- Real-time prices, in $/MWh, including:
  - 5-minute LMPs of *energy* at:

  - *Intertie metering points* for imports and exports;
  - *Delivery points* for dispatchable *generation facilities*, combustion turbines, steam turbines, *dispatchable loads* and price responsive loads; and
  - *Delivery points* for *non-dispatchable loads*;
- 5-minute LMPs of *operating reserve* at:
  - *Intertie metering points* for imports and exports; and
  - *Delivery Points* for dispatchable *generation facilities*, combustion turbines, steam turbines and *dispatchable loads;*
- 5-minute *ICPs* at *intertie metering points*;
- Hourly zonal LMP for the Ontario zone;
- 5-minute *intertie settlement* prices of *energy* at *intertie metering points*; and
- 5-minute *intertie settlement* prices of *operating reserve* at *intertie metering points*.

- Real-time schedules including:
  - 5-minute schedules for *energy* injection, in MWh, at:
    - *Intertie metering points* for imports; and
    - *Delivery points* for dispatchable *generation facilities*, *pseudo-units*, combustion turbines and steam turbines;
  - 5-minute schedules for energy injection, MWh at:
    - *Delivery points* for the steam turbine portion of *pseudo-units*; and
    - *Delivery points* for the combustion turbine portion of *pseudo-units;*
  - 5-minute schedules for *energy* withdrawal, in MWh, at:
    - *Intertie metering points* for exports; and
    - *Delivery points* for *dispatchable loads*;
  - 5-minute schedules for 10-minute spinning *operating reserve*, in MW, at:
    - *Delivery points* for dispatchable *generation facilities*, combustion turbines, steam turbines and *dispatchable loads*;
  - 5-minute schedules for 10-minute non-spinning and 30-minute *operating reserve*, in MW, at:
    - *Intertie metering points* for imports;
    - *Delivery points* for dispatchable *generation facilities*, combustion turbines, steam turbines and *dispatchable loads*.

For detailed descriptions, attributes, and usage of this data, refer to Sec 3.5.6 Collection of Real-Time Market Data.

Flow	**Source**	**Target Processes**	**Frequency**
AQEI and AQEW Data	Meter Data Management System	Process P1	Daily

The data flow for allocated quantity of *energy* injected (AQEI) and allocated quantity of *energy* withdrawn (AQEW) pertains to all *metering data* received from *registered wholesale meters* totalized and allocated to each *delivery point* by the Meter Data Management System (MDMS) for all *registered facilities* including physical *demand response contributor* data.

The data for virtual *demand response contributors* embedded in the distribution system is not part of this flow, which is described in the flow 'Virtual HDR Resource AQEW data' into Process P4.

This flow includes:

- *Settlement* variables: AQEW and AQEI data series for *delivery points* within Ontario, in MWh;

The usage of these variables in the context of the DAM is described in Section 3.6.2 DA and RT Energy and OR Settlement: Second Settlement of this document.			
Flow	**Source**	**Target Processes**	**Frequency**
DAM and RTM PBC Data	Offers, Bids and Data Inputs	Process P1	Within (7) calendar days prior to the *dispatch day* and (6) *business days* after the *dispatch day*

Description:

This data flow includes *real-time market physical bilateral contract data* (RT PBC data) and day-ahead market *physical bilateral contract data* (DA PBC data). This data is submitted by a *selling market participant* to facilitate *settlement* by the *IESO* of an agreement with a *buying market participant* to assume payment responsibility for *energy* and portions of uplift *settlement amounts* for *energy* bought and sold at *delivery points* and *intertie* metering points.

- *Physical bilateral contract data* submission requirements for both the day-ahead market and the *real-time market* are described in Section 3.4.9 in the Offers, Bids and Data Inputs detailed design document.
- DAM *physical bilateral contract data* elements are defined in Section 3.5.4: Table 3-18 of this design document.
- Real-time *physical bilateral contract data* elements are defined in Section 3.5.6, Table 3-36 of this design document.
- Submission of *physical bilateral contract data* must comply with the timelines specified in Section 3.4.9 of the Offer, Bids and Data Inputs detailed design document.

6.1.2 Process P2 – Calculate Credits, Charges, Uplifts Settlement Amounts

6.1.2.1 Description

Process P2 collects *settlement*-ready data required for the calculation of *settlement amounts* for day-ahead market and *real-time market* charges, credits and uplifts as described in Section 3.7 of this design document. To accomplish this, this process makes use of the following:

- Authorization and Participation data;
- Facility Registration data;
- Select *facilities* registration parameters used to determine generator offer guarantees;
- Prices, schedules, and operational commitments produced by the DAM calculation engine, PD calculation engine and RT calculation engine;
- Allocated quantities of *energy* injected or withdrawn from the *IESO-controlled grid;*
- Financial and non-financial *dispatch data* submitted by market participants;
- Market integration and remediation data; and
- Market power mitigation data produced by ex-ante and ex-post mitigation processes.

Table 6-2 summarizes the various input and output data flows for Process P2.

6.1.2.2 Input and Output Data Flows

Table 6-2: Process P2 Input and Output Data Flows

<table>
<tr><th>Flow</th><th>Source</th><th>Target Processes</th><th>Frequency</th></tr>
<tr><td>Organization and Participation Authorization Data</td><td>Authorization and Participation</td><td>Process P2</td><td>Current organization data are communicated for each trading day.</td></tr>
<tr><td colspan="4">Description:
This data flow is concurrent with the data flow defined for Process P1. In summary, the settlement process will utilize the following organization and participation authorization data:
• Market participant name and identification number;
• Current authorization for participation granting trading privileges to each market participant; and
• Current authorization for each market participant for access to resources.
Refer to Table 6-1 for details of organization and participation authorization data.</td></tr>
<tr><th>Flow</th><th>Source</th><th>Target Processes</th><th>Frequency</th></tr>
<tr><td>Market Participant Associations and Facility Registration Data</td><td>Facility Registration</td><td>Process P2</td><td>Current facilities data are communicated for each trading day.</td></tr>
<tr><td colspan="4">Description:
This data flow is concurrent with the data flow defined for Process P1. In summary, the settlement process will utilize the following market participant associations and facility registration data:
• Mutually exclusive facility sub-classifications;
• Physical facility resource identifiers;
• Organizational roles and responsibilities;
• Market participant associations to boundary entities;
• Market participant associations to virtual transaction zonal trading entities;
• Market participant associations to physical and virtual hourly demand response resources;
• Transmission customer associations for every transmission tariff delivery point established by a transmitter for transmission service; and
• Delivery points associated with suppliers of ancillary services.
Refer to Table 6-1 for details of the above listed data.
The settlement process required for the future day-ahead market and the real-time market will use a number of facility registration parameters listed in Section 3.5.2. For determination of generator offer guarantee payments, the following parameters are required by the settlement process:
o Elapsed Time to Dispatch applicable to NQS generation units; and
o Start Indication Value applicable to hydroelectric generation facilities.
These registration parameters are static and updated as required by the Facility Registration process.</td></tr>
</table>

Flow	Source	Target Processes	Frequency
DAM Prices and Schedules	DAM Calculation Engine	Process P2	Daily for each *dispatch hour*

Description:

This data flow is concurrent with the data flow defined for Process P1. In summary, the *settlement process* will utilize the following day-ahead pricing and schedule data:

- DAM prices, in $/MWh, including:
    - Hourly LMPs for *energy*:
    - Hourly LMPs for o*perating reserve*,
    - Hourly *ICPs* at *intertie metering points*; and
    - Hourly zonal LMP for the Ontario zone for *energy* for *non-dispatchable loads*.
- DAM schedules including:
    - Hourly schedules for *energy* injection, in MWh;
    - Hourly schedules for *energy* withdrawal, in MWh; and
    - Hourly schedules for supply of 10-minute spinning, 10-minute non-spinning and 30-minute *operating reserve* in MW.

Refer to Table 6-1 for details of day-ahead market pricing and schedule data.

Flow	Source	Target Processes	Frequency
DAM Commitments	DAM Calculation Engine	Process P2	Daily for each *dispatch hour*

Description:

This data flow is concurrent with the data flow defined for Process P1. In summary, the *settlement process* will utilize the following day-ahead commitment data:

DAM unit commitment data, including:

- Hourly schedules, in MWh, from the last DAM calculation engine pass prior to the *reliability* scheduling pass for *energy*;
- Hourly schedules, in MWh, from the *reliability* scheduling pass of the DAM calculation engine for *energy*;
- Hourly schedules, in MW, from the last DAM calculation engine pass prior to the *reliability* scheduling pass for 10-minute spinning, 10-minute non-spinning and 30-minute *operating reserve*; and
- Hourly schedules, in MW, from the *reliability* scheduling pass of the DAM calculation engine for 10-minute spinning, 10-minute non-spinning and 30-minute *operating reserve*.

Refer to Table 6-1 for details of day-ahead market commitment data.

Flow	Source	Target Processes	Frequency
PD Commitments and Schedules, Advisory Prices	PD Calculation Engine	Process P2	Daily for each *dispatch hour*

Description:

This data flow is concurrent with the data flow defined for Process P1. In summary, the *settlement process* will utilize the following pre-dispatch commitment, schedule and advisory price data:

- Advisory PD prices, in $/MWh, including:
    - Hourly pre-dispatch LMP for *energy*; and

- Hourly LMPs for *energy* for a given pre-dispatch run;
- Advisory PD schedules, in MWh, including:
  - Hourly pre-dispatch schedules for *energy* injection at *intertie metering points*;
  - Hourly schedules for *energy* injection for a given pre-dispatch run at:
    - *Delivery points* for NQS *generation facilities*, *pseudo-units*, combustion turbines and steam turbines;
  - Hourly schedules for the steam turbine portion quantity for *energy* injection for a given pre-dispatch run at *delivery points* for *pseudo-units*; and
  - Schedules for *energy* withdrawal at *intertie metering points* for exports.
- PD unit commitment events, including: Hourly schedules, in MWh, for *energy* injected for a given pre-dispatch run at *delivery points* for NQS *generation facilities*:
  - Hourly schedules, in MW, for 10-minute spinning, 10-minute non-spinning, and 30-minute *operating reserve* for a given pre-dispatch run at *delivery points* for NQS *generation facilities*.

Refer to Table 6-1 for details of pre-dispatch commitment data.

Flow	Source	Target Processes	Frequency
RT Prices and Schedules	RT Calculation Engine	Process P2	Daily for each *dispatch interval*

Description:

This data flow is concurrent with the data flow defined for Process P1. In summary, the *settlement process* will utilize the following *real-time market price* and schedule data:

- Real-time prices, in $/MWh, including:
  - 5-minute LMPs of e*nergy*;
  - 5-minute LMPs of *operating reserve*;
  - 5-minute ICPs at *intertie metering points*;
  - Hourly zonal LMP for the Ontario zone;
  - 5-minute *intertie settlement* prices of *energy* at *intertie metering points*; and
  - 5-minute *intertie settlement* prices of *operating reserve* at *intertie metering points*.
- Real-time schedules including:
  - 5-minute schedules for *energy* injection, in MWh;
  - 5-minute schedules for *energy* injection, MWh;
  - 5-minute schedules for *energy* withdrawal, in MWh; and
  - 5-minute schedules for 10-minute spinning, 10-minute non-spinning and 30-minute *operating reserve*, in MW.

Refer to Table 6-1 for details of real-time price and schedule data.

Flow	Source	Target Processes	Frequency
AQEI and AQEW data	Meter Data Management System	Process P2	Daily

This data flow is concurrent with the data flow defined for Process P1. In summary, the *settlement process* will utilize the following real-time allocated quantity of *energy* injected (AQEI) and allocated quantity of *energy* withdrawn (AQEW) data.

This data flow includes:

- AQEW and AQEI data series for all *delivery points* within Ontario, in MWh.

Refer to Table 6-1 for details of real-time data for *energy* injected or withdrawn from the *IESO-controlled grid*.

Flow	Source	Target Processes	Frequency
Financial Dispatch Data	Offers, Bids and Data Inputs	Process P2	Daily for each *dispatch hour*

Description:

Financial *dispatch data* parameters comprise *offer* and *bid* data submitted for physical transactions by *market participants* for *energy* and *operating reserve* into the day-ahead market and the *real-time market*. Financial *dispatch data* may be submitted into the day-ahead market, pre-dispatch, and the *real-time market* and may be revised by the *registered market participant* in any hour subject to restrictions described in the Grid and Market Operations Integration detailed design document. Financial *dispatch data* for physical *facilities* may also be subject to market power mitigation for economic withholding.

Financial Dispatch Data for Physical Transactions Submitted to the DAM

- Hourly *energy offers* for:
  - *Intertie* import transactions;
  - Dispatchable *generation facilities*; and
  - *Pseudo-units* and associated combustion turbines and steam turbines;
- Hourly start-up offers for:
  - NQS *generation facilities*; and
  - *Pseudo-units*.
- Hourly speed no-load offers for:
  - NQS *generation facilities; and*
  - *Pseudo-units.*
- Hourly *bids* for *energy* for:
  - *Intertie* export transactions;
  - *Dispatchable loads*; and
  - Price responsive loads.
- Hourly *operating reserve offers* for:
  - *Intertie* import transactions;
  - Dispatchable *generation facilities*; and
  - *Dispatchable loads.*

For detailed descriptions, attributes and usage of the above financial *dispatch data* parameters, refer to Section 3.5.4, Table 3-15.

Financial Dispatch Data for Physical Transactions Submitted to Pre-Dispatch

- Hourly *energy offers* per pre-dispatch run for:
  - *Pseudo-units*.
- Hourly start-up offers per pre-dispatch run for:
  - NQS *generation facilities*;
  - *Pseudo-units*; and
  - *Pseudo-units* with combustion turbine failure.

- Hourly speed no-load offers for:
  - Non-quick start *generation facilities*; and
  - *Pseudo-units.*
- Hourly *bids* for *energy* for:
  - *Intertie* export transactions;
  - *Dispatchable loads*; and
  - Price responsive loads.

For detailed descriptions, attributes and usage of the above financial *dispatch data* parameters, refer to Section 3.5.4 Table 3-25.

Financial Dispatch Data for Physical Transactions Submitted to the RTM

- Hourly *energy offers* for:
  - *Intertie* import transactions;
  - Dispatchable *generation facilities*; and
  - *Pseudo-units* and associated combustion turbines and steam turbines.
- Hourly start-up offers for:
  - Non-quick start *generation facilities*; and
  - *Pseudo-units*.
- Hourly speed no-load offers for:
  - Non-quick start *generation facilities;* and
  - *Pseudo-units.*
- Hourly *bids* for *energy* for:
  - *Intertie* export transactions; and
  - *Dispatchable loads*.
- Hourly *operating reserve offers* for:
  - *Intertie* import transactions;
  - Dispatchable *generation facilities;*
  - *Pseudo-units*; and
  - *Dispatchable loads.*

For detailed descriptions, attributes and usage of the above financial *dispatch data* parameters, refer to Section 3.5.6, Table 3-33.

Flow	Source	Target Processes	Frequency
Non-Financial Dispatch Data	Offers, Bids and Data Inputs	Process P2	Daily for each *dispatch hour*

Description:

Non-financial *dispatch data* may be submitted into the day-ahead market, pre-dispatch, and the *real-time market*. Hourly and daily *dispatch data* parameters may be revised by the *registered market participant* in any hour subject to restrictions described in the Grid and Market Operations Integration detailed design document.

The non-financial *dispatch data* parameters listed in Table 3-9 are used by the *settlement process* in the calculation of *settlement amounts* for make-whole payments or generator offer guarantees or the determination of eligibility for such payments.

- Hourly must run – hourly parameter submitted for:
    - Dispatchable hydroelectric *generation facilities*.
- Minimum hourly output - hourly parameter submitted for:
    - Dispatchable hydroelectric *generation facilities*.
- Minimum daily *energy* limit – daily parameter submitted for:
    - Dispatchable hydroelectric *generation facilities*.
- *Maximum number of starts per day* – daily parameter submitted for:
    - Dispatchable *generation facilities*.
- *Forbidden regions* – daily parameter submitted for:
    - Dispatchable hydroelectric *generation facilities.*
- *Minimum loading point* (MLP) – daily parameter submitted for:
    - NQS *generation facilities;*
    - *Pseudo-units* and associated combustion turbines and steam turbines.
- *Minimum generation block run-time* – daily parameter submitted for:
    - NQS *generation facilities*; and
    - *Pseudo-units* and associated combustion turbines and steam turbines.
- *Minimum generation block down-time* – daily parameter submitted for:
    - *Pseudo-units* and associated combustion turbines and steam turbines.
- Ramp Up Energy to MLP (ramp hours to MLP; and *energy* per ramp hour) – daily parameter submitted for:
    - NQS *generation facilities.*
- Single cycle mode – daily parameter submitted for:
    - *Pseudo-units* and associated combustion turbines and steam turbines.
- Linked resources, Time lag, MWh – daily parameter submitted for:
    - Dispatchable hydroelectric *generation facilities.*

Refer to Table 3-9 in Section 3 for further details and usage of these parameters.

Flow	Source	Target Processes	Frequency
Market Integration and Remediation Data	Grid and Market Operations Integration	Process P2	Event-based

Description:

This flow includes all data to be received resulting from the interaction of operation of the *energy market* and operation of the *IESO-controlled grid*.

- Market integration data:
    - Failure charge codes for *intertie* schedule adjustments and curtailments as defined in the Grid and Market Operations Integration detailed design, Section 3.6.3 Table 3-1.

- *Intertie* reason codes for eligibility for make-whole payments and *intertie* failure charges as defined in Section 3.7 Table 3-54.

- Market failure and errors:
  - The *settlement process* must be informed of all calculation engine failures and errors in the day-ahead market through to real-time. In the event of calculation engine failures to produce prices and/or errors found in prices, the prices are determined by internal *IESO* staff manually using prices from time intervals prior to the failure. In this event, the corrected data will be automatically pushed to the *settlement process*.
  - The processes for market remediation in the day-ahead market, pre-dispatch, and real-time market are defined respectively in Sections 3.9.1, 3.9.2 and 3.9.3 of the Grid and Market Operations Integration detailed design document.

Flow	Source	Target Processes	Frequency
Make-Whole Payment Impact Thresholds	Market Power Mitigation Information System	Process P2	Current impact thresholds are communicated for each *trading day*.

Description:

Process P2 will receive a set of make-whole payment impact thresholds from Market Power Mitigation Information System to carry out the Settlement Mitigation process defined in Section 3.8 of the Market Power Mitigation detailed design document.

- Table 3-16: Make-Whole Impact Thresholds for NCAs and DCAs
- Table 3-18: Make-Whole Payment Impact Thresholds for BCAs
- Table 3-20: Make-Whole Payment Impact Thresholds for Reliability Constraints
- Table 3-22: Make-Whole Payment Impact Thresholds for Global Market Power – Energy
- Table 3-24: Make-Whole Payment Impact Thresholds for Local Market Power – Operating Reserve
- Table 3-26: Make-Whole Payment Impact Thresholds for Global Market Power – Operating Reserve

The application of the make-whole payment impact thresholds is dependent on the Resource Constrained Area Mitigation Test Conditions for each resource as identified in Tables 3-12, 3-21, and 3-29 respectively for the DAM calculation engine, PD calculation engine and RT calculation engine.

The *settlement amount*s subject to *settlement* mitigation for make-whole payments are described in Section 3.13. Make-whole payment impact thresholds will also be utilized for the Settlement Process for Mitigating Dual Fuel Resources described in Section 3.12 of the Market Power Mitigation detailed design document.

Flow	Source	Target Processes	Frequency
Reference Level Values for DAM, PD and RT	Market Power Mitigation Information System	Process P2	Daily for each *dispatch hour*

Description:

Based on reference level formulas determined by the *IESO*, reference level values for each *generation unit* supplying *energy* and/or *operating reserve* are updated daily by the *IESO* using fuel and other cost indices applicable to financial *dispatch data* parameters.

Reference level values used by, or available to, the DAM calculation engine, PD calculation engine and RT calculation engine will be made available to the *settlement process* including:

- *Energy offers* for:
  - o Dispatchable *generation units*.
- Start-up offers for:
  - o Non-quick start *generation units*;
  - o *Pseudo-units* and related combustion turbines and steam turbines.
- Speed no-load offers for:
  - o Non-quick start *generation units*; and
  - o *Pseudo-units* and related combustion turbines and steam turbines.
- *Operating reserve offers* for:
  - o Dispatchable *generation units*;
  - o Non-quick start *generation units*; and
  - o *Pseudo-units* and related combustion turbines and steam turbines.

Dual-fuel resources that have the capability to use two types of fuel to generate electricity can opt to select any one of the fuel types at any given time, and thus reference level values for such generation resources can vary through the day and will be used for the Settlement Process for Mitigating Dual Fuel Resources described in Section 3.12 of the Market Power Mitigation detailed design document.

Flow	**Source**	**Target Processes**	**Frequency**
Mitigation Test Results	DAM, PD and RT Calculation Engines	Process P2	Daily for each dispatch hour

Description:

Ex-ante mitigation for economic withholding can result in the failure of conduct tests for each of the financial *dispatch data* parameters. The results of these conduct tests performed by the DAM, PD and RT calculation engines and the system conditions under which these conduct tests are performed are required by the *settlement process* to determine the need for and application of make-whole payment impact test thresholds.

Mitigation test result data will be provided to the *settlement process* by the DAM engine, PD and RT calculation engines for *generation units* subjected to conduct testing and will include the following for each financial *dispatch data* parameter:

- Conduct test results at each *delivery point* for each hour for the DAM and pre-dispatch, and each interval for the *real-time market*;
- Impact test results at each *delivery point* for each hour for the DAM and pre-dispatch, and each interval for the *real-time market*; and
- Constrained area mitigation conditions at each *delivery point* for each hour for the DAM and pre-dispatch, and each interval for the *real-time market.*

Flow	Source	Target Processes	Frequency
Enhanced Mitigated Dispatch Data	DAM, PD and RT Calculation Engines	Process P2	Daily for each *dispatch hour* for DA, PD, and RT time periods

Description:

The DAM, PD and RT calculation engines generate mitigated for conduct *dispatch data* upon failure of ex-ante mitigation of economic withholding conduct tests for each generation resource. Such mitigated for conduct *dispatch data* is the replacement of financial *dispatch data* parameters submitted by the *market participant* with the reference level value for parameters that fail the conduct test.

If the conditions are met for more than one constrained area for the same resource in the same commitment period, hour, or interval, then the mitigation of make-whole payments will be tested using the most restrictive set of conduct thresholds. The resulting mitigated *dispatch data* is referred to as enhanced mitigated for conduct *dispatch data*.

Enhanced mitigated for conduct *dispatch data* will be provided to the *settlement process* by the DAM, PD and RT calculation engines for *generation units* subjected to conduct testing and will include:

- Mitigated *dispatch data* for *energy offers* at each *delivery point* for each hour for the DAM and pre-dispatch, and each interval for the *real-time market*;
- Mitigated *dispatch data* for start-up offers at each *delivery point* for each hour for the DAM and pre-dispatch, and each interval for the *real-time market*;
- Mitigated *dispatch data* for speed no-load offers at each *delivery point* for each hour for the DAM and pre-dispatch, and each interval for the *real-time market;* and
- Mitigated *dispatch data* for *operating reserve offers* at each *delivery point* for each hour for the DAM and pre-dispatch, and each interval for the *real-time market.*

Enhanced mitigated for conduct *dispatch data* will be used by the *settlement process* for *settlement* mitigation of make-whole payments as described in Section 3.8 of the Market Power Mitigation detailed design document and applied to make-whole payments and other guarantee payments as specified in Section 3.13 of this design document.

Flow	Source	Target Processes	Frequency
Ex-Post Mitigation Settlement Charges	Ex-Post Mitigation	Process P2	Event-based

Description:

The ex-post mitigation process may result in the calculation of *settlement* charges. These charges result from the Ex-Post Mitigation for Physical Withholding process defined in Section 3.9 of the Market Power Mitigation detailed design document, and Ex-Post mitigation for Economic Withholding on Uncompetitive Interties process defined in Section 3.10 of the Market Power Mitigation detailed design document.

The ex-post mitigation activities will be performed after final *settlement* for any *trading day* and will result in the following charges processed through *settlement*:

- Ex-post mitigation for physical withholding settlement charge – EXP_PWSC; and
- Ex-post mitigation for economic withholding in uncompetitive interties – EXP_EWSC.

Flow	Source	Target Processes	Frequency
Demand Determinants	Transmission Tariff Demand Calculator	Process P2	Daily

Description:

This flow includes all data currently received from the Transmission Tariff Demand Calculator:

- This includes demand determinants for all transmission tariff *delivery points*, and intertie transactions for:
    - Line connection service in MW;
    - Transformation connection service in MW;
    - Network service in MW, and
    - Export transmission service in MWh.
- These *settlement* data variables and the calculation of transmission tariff *settlement amounts* are unaffected by MRP.

Flow	Source	Target Processes	Frequency
Settlement Amounts	Process P2	Market Billing and Funds Administration	Daily

Description:

- This data flow includes all *settlement amounts* computed in Process P1, P2, which will be sent to the Market Billing and Funds Administration process.

Flow	Source	Target Processes	Frequency
Settlement Amounts	Process P2	Prudential Security	Daily

Description:

This data flow includes:

- All *settlement amount* data including *energy* and OR settlement produced on a daily cycle in the *settlement process;*
- Data that also gets *published* in the following statements:
    - *Preliminary settlement statement* data (physical transactions and virtual transactions); and
    - *Final settlement statement* data (physical transactions and virtual transactions).

The data components listed above are used by the Prudential Security process to calculate the Settled-but-Not-Invoiced (SNI) component of *actual exposure* for physical transactions and virtual transactions. For more information, refer to Prudential Security detailed design document Section 6: Table 6-1-10 Actual Exposure Data collection process.

Flow	Source	Target Processes	Frequency
Energy and OR Settlement Amounts	Process P2	Process P5	Daily

Description:

This data flow includes:

- All *settlement amounts* computed in Process P1, P2, which need to be sent to process P5 to allow for the production of the *preliminary* and *final settlement statements* and *settlement* data files.
- Refer to Appendix D for a listing of the energy and OR *settlement amount* charges.

6.1.3 Process P3 – Calculate TR Auction Settlement Amounts

6.1.3.1 Description

Process P3 uses the quantities and auction prices of DAM *transmission rights* awarded to *TR market participants*. Within this process, *settlement amounts* are calculated reflecting the value of the *TRs* awarded – as priced by the *TR market*. These *settlement amounts* then form the basis of *TR market settlement statements* issued to *market participants* and other data flows to downstream processes.

Currently, *TR auction* amounts are settled through the Transmission Rights Auction Settlement Debit (see the current IESO Charge Types and Equations for further details). As described in Section 3.7.15 with the introduction of the day-ahead market and LMPs *settlement* of the *TR market* will incorporate day-ahead LMPs.

Process P3 outputs are scrutinized by a downstream Quality Control process (P6). In the event that a problem is found in regards to the completeness or accuracy of *TR auction settlement amounts*, the nature of the problem will be signalled back to Process P3, coupled with a re-run request if required.

Input and Output Data Flows

Table 6-3:Process P3 Input and Output Data Flows

<table>
<tr><th>Flow</th><th>Source</th><th>Target Processes</th><th>Frequency</th></tr>
<tr><td>TR Quantities and Prices</td><td>Transmission Rights Auction</td><td>Process P3</td><td>Once per month for short-term transmission rights; Twice per month for scheduled long-term transmission rights</td></tr>
<tr><td colspan="4">Description:
The following data elements are passed to Process P3 for settlement of TR auction results.
The TR market clearing price for each transmission right in a single round of a TR auction, in $/MW; and
Quantity of transmission rights owned, in MW, by TR holder for a given hour from a given injection TR zone to a given withdrawal TR zone.</td></tr>
<tr><th>Flow</th><th>Source</th><th>Target Processes</th><th>Frequency</th></tr>
<tr><td>Organization and Participation Authorization Data</td><td>Authorization and Participation Data</td><td>Process P3</td><td>Current organization data are communicated for each trading day.</td></tr>
<tr><td colspan="4">Description:
The TR auction settlement process will utilize the following organization and participation authorization data:
Market participant name and identification number; and
Current authorization for participation granting trading privileges to each market participant's authorization to trade for transmission rights in the TR auction.</td></tr>
</table>

Flow	Source	Target Processes	Frequency
TR Settlement Amounts	Process P3	Process P5 and Market Billing Funds Administration	Daily
Description: • These *settlement amounts* represent the amounts owing from *market participants* to the *IESO* for each series of DAM *transmission rights*, as priced by the *TR auction*.			

6.1.4 Process P4 – Calculate DR Auction Settlement Amounts

6.1.4.1 Description

This process calculates payments to and charges from *demand response market participants* arising from *demand response capacity obligations* that they have acquired through the *demand response auction* for a given *commitment period*. These *settlement amounts* are independent of the market *settlement process* for *energy* and *operating reserve*, though they rely on inputs and outputs from the *energy market*, through which *demand response market participants* fulfil their obligation to provide *demand response capacity.*

This process determines:

- Availability payments made to *demand response market participants* who have a *demand response capacity obligation* within a given *commitment period*;
- Availability, administration, buy-out, capacity, and dispatch charges for *demand response market participants* who do not fulfil their *demand response capacity obligation* per the *market rules* that govern the *demand response auction* and the requirements of Market Manual Part 12.0 – Demand Response Auction.

6.1.4.2 Input and Output Data Flows

Table 6-4: Process P4 Input and Output Data Flows

Flow	Source	Target Processes	Frequency
Hourly Demand Response Dispatch Data	Offers, Bids and Data Inputs	Process P4	Daily
Description: • This data flow includes *bids* from *hourly demand response* resources and *dispatchable loads* during the resource *commitment period* and submitted by the *market participant* to the future day-ahead market prior to the close of the DAM submission window. • This data is used to ensure that *demand response market participants* are fulfilling their *demand response capacity obligation* through participation in the *energy market.*			

Flow	Source	Target Processes	Frequency
RT Hourly Demand Response Activation Schedules	RT Calculation Engine	Process P4	Daily

Description:

- This data flow includes:
  - The schedules, in MWh, for *energy* scheduled for withdrawal at *delivery points* for *hourly demand response* resources *during the commitment period* defined by the *demand response capacity obligation*.

Flow	Source	Target Processes	Frequency
Demand Response Capacity Obligation Data and Prices	Demand Response Auction	Process P4	Once per commitment period, or as needed in the event of an approved change to a capacity obligation

Description:

- This data flow includes:
  - The *demand response auction* price, in $/MW-day, established through the *demand response auction*, which forms the basis of the availability payment for *demand response market participants* with a *demand response capacity obligation*; and
  - For the *demand response auction, demand response market participants* receive a *demand response capacity obligation*, in MW, which must be fulfilled through participation in the *energy market*.

Flow	Source	Target Processes	Frequency
Virtual and Physical HDR Resource AQEW data	Meter Data Management System	Process P2	Daily for physical HRD contributors, Monthly for virtual HDR contributors

Description:

This data flow comprises *metering data* for virtual contributors to *hourly demand response* resources embedded in the *distribution system* and used to deliver *demand response capacity*. This data flow also includes *metering data* for physical contributors to *hourly demand response* resources collected by the *IESO*.

Metering data for virtual *hourly demand response* resources is metered by local distribution companies (LDC) revenue meters and submitted by *demand response market participants* using the Online IESO system. This data is stored in the *IESO metering database* as defined in Market Manual Part 12.0 for the *demand response auction*. Physical contributors to *hourly demand response* resources are directly connected to the *IESO-controlled grid* or may be embedded in the *distribution system*. In both instances, *metering data* is collected by the *IESO*.

This information is used to determine the *availability* and performance of *hourly demand response* resources in fulfilling their obligation to provide *demand response capacity* and reduce their *energy* consumption in response to *demand response* activation notices.

This data flow includes:

- AQEW data series for *delivery points* for physical *hourly demand response* resources including:
  - *Dispatchable loads* providing *demand response capacity*;

- *Transmission system*-connected physical contributors providing *demand response capacity*;
- *Distribution system* embedded physical contributors providing *demand response capacity*; and
- Price responsive loads providing *demand response capacity*.

AQEW data series for virtual *hourly demand response* resource contributors in the West, Southwest, Bruce, Niagara, Toronto, East, Ottawa, Essa, Northwest, and Northeast electrical zones for *metering data* submitted by each *demand response market participant*.

Flow	Source	Target Processes	Frequency
DR Settlement Amounts	Process P4	Process P5 and Market Billing and Funds Administration	Monthly

Description:

This data flow will include DR Settlement Amounts, including:

- Availability payments to be made to *demand response market participants* with a *demand response capacity obligation;*
- Availability charges applied to *demand response market participants* including:
  - administration charges,
  - buy-out charges,
  - capacity charges, and
  - dispatch charges.

6.1.5 Process P5 – Produce Settlement Statements and Data Files

6.1.5.1 Description

Process P5 is collects the *settlement amounts* received from Processes P1, P2, P3 and P4 and data used by the *settlement process* including:

- *Energy* and *operating reserve* market *settlement amounts*;
- *TR auction settlement amounts*;
- *Demand response auction settlement amounts*;
- Hourly, daily and other *dispatch data* submitted by *market participants*;
- AQEW and AQEI data received the Meter Data Management System; and
- NoD resolution details from Process P7.

Data received is processed to create the various *settlement* charge type amount line items to be presented on *preliminary* and *final settlement statements*. Process P5 also creates a corresponding data file for each *physical market settlement statement*. This *settlement* data file includes all the relevant data used to calculate the *settlement amounts* in order to allow *market participants* to validate and recreate those *settlement amounts*.

6.1.5.2 Input and Output Data Flows

Table 6-5: Process P5 Input and Output Data Flows

Flow	Source	Target Processes	Frequency
Energy and OR Settlement Amounts	Process P1, Process P2	Process P5	Daily

Description:

This data flow includes all *settlement amounts* computed in Process P1 and Process P2, which include:

From Process P1:

- Day-ahead market and *real-time market settlement amounts* in the *energy* and *operating reserve markets* are described as outputs in Table 6-1 including:
  - First settlement – *settlement amounts* for *energy* and *operating reserve* that can be completely calculated on the basis of *settlement*-ready data from the DAM calculation engine;
  - Second *settlement –settlement amounts* that can be calculated on the basis of *settlement*-ready data from the DAM calculation engine reconciled with the *real-time market* results and actual quantities of *energy* injected or withdrawn from the *IESO-controlled grid*.

From Process P2:

- Day-ahead market and *real-time market* charges, credits and uplifts as calculated in Process P2, described as outputs in Table 6-2.

Flow	Source	Target Processes	Frequency
TR Settlement Amounts	Process P3	Process P5	Weekly

Description:

This data flow includes all *TR settlement amounts* computed in Process P3, which include:

- The *TR market* clearing price for each *transmission right* in a single round of a *TR auction*, in $/MWh.
- Quantity of *transmission rights* owned, in MW, by a *TR holder* for a given hour from a given injection *TR zone* to a given withdrawal *TR zone.*

Flow	Source	Target Processes	Frequency
DR Settlement Amounts	Process P4	Process P5	Monthly

Description:

This data flow includes all DR Settlement Amounts computed in Process P4, which include:

- Availability payments to be made to *demand response market participants* with a *demand response capacity obligation*.
- Availability charges, administration charges, buy-out charges, capacity charges and *dispatch* charges applied to *demand response market participants*.

Flow	Source	Target Processes	Frequency
Hourly and Daily Dispatch Data	Offers, Bids and Data Inputs	Process P5	Daily

Description:

This data flow includes:

- Hourly and daily *dispatch data* used by the DAM calculation engine including both *energy* and OR *offers* and *bids*;
- Hourly and daily *dispatch data* used by the PD calculation engine including both *energy* and OR *offers* and *bids*; and
- Hourly and daily *dispatch data* used by the RT calculation engine including both *energy* and OR *offers* and *bids*.

Flow	Source	Target Processes	Frequency
HDR Dispatch Data	Offers, Bids and Data Inputs	Process P5	Daily

Description:

- This data flow includes *bids* for *hourly demand response* (HDR) resources during the resource *commitment period* and submitted by the *market participant* to the future day-ahead market prior to the close of the DAM submission window.

Flow	Source	Target Processes	Frequency
Variable Generation Offer Data	Offers, Bids and Data Inputs	Process P5	Daily

Description:

Market participants may elect to submit *dispatch data* into the DAM to represent the hourly forecast of *variable generation* for their *facilities* rather than the forecast provided by the *IESO's* centralized forecast of *variable generation facilities*.

This flow includes:

- Hourly offers for *variable generation facilities* submitted by *variable generators* into the day-ahead market to be used in lieu of the *IESO* centralized forecast for those same *variable generation facilities.*

Flow	Source	Target Processes	Frequency
DAM and RTM PBC Data	Offers, Bids and Data Inputs	Process P5	Daily

Description:

This data flow includes *real-time market physical bilateral contract data* (RTM PBC data) and day-ahead market *physical bilateral contract data* (DAM PBC data). This data is submitted by a *selling market participant* to facilitate *settlement* by the *IESO* of an agreement with a *buying market participant* to assume payment responsibility for *energy* and portions of uplift *settlement amounts* for *energy* bought and sold at *delivery points* and *intertie* metering points.

- *Physical bilateral contract data* submission requirements for both the day-ahead market and the *real-time market* are described in the Offers, Bids and Data Inputs detailed design document Section 3.4.9.

- o DAM *physical bilateral contract data* elements are defined in Section 3.5.4, Table 3-18 of this design document.
- o Real-time *physical bilateral contract data* elements are defined in Section 3.5.6, Table 3-36 of this design document.
- o Submission of *physical bilateral contract data* must comply with the timelines specified in Section 3.4.9 of the Offer, Bids and Data Inputs detailed design document.

Flow	Source	Target Processes	Frequency
AQEI and AQEW Data	Meter Data Management System	Process P5	Daily

Description:

The data flow for allocated quantity of *energy* injected (AQEI) and allocated quantity of *energy* withdrawn (AQEW) pertains to all *metering data* received from *registered wholesale meters* totalized and allocated to each *delivery point* by the Meter Data Management System (MDMS) for all *registered facilities* including physical *demand response contributor* data.

This data flow provides the AQEW and AQEI data series for *delivery points* within Ontario, in MWh including;

- *Energy* injected (AQEI) by *registered facilities* metered by the *IESO* with a *registered wholesale meter (RWM)* at *delivery points* for:
  - o Generation facilities.
- *Energy* withdrawn (AQEW) by *registered facilities* metered by the *IESO* with an *RWM* at *delivery points* for:
  - o *Dispatchable loads;*
  - o *Non-dispatchable loads;*
  - o *Load facilities* embedded in the *distribution system and metered by an IESO RWM;*
  - o Physical contributors to *hourly demand response* resources; and
  - o Price responsive loads.

Flow	Source	Target Processes	Frequency
Energy/OR/DR Preliminary Settlement Statements	Process P5	Market Participant	10 *business days* after the *trading day* in accord with the *Settlement Schedule and Payment Calendar*

Description:

- Process P5 issues *preliminary settlement statements* for the *physical market* and virtual *energy* transactions ten *business days* after each *trading day*. With each *preliminary settlement statement,* a *preliminary settlement* data file is also issued, as described in ‘Energy/OR/DR Data Files’.
- P5 generates *preliminary settlement statements* for each *trading day*, but they are issued to *market participants* only on *business days*. This means that on some days, more than one *preliminary settlement statement* is issued.

Flow	Source	Target Processes	Frequency
Energy/OR/DR Final Settlement Statements	Process P5	Market Participant	20 *business days* after the trading day in accord with the *Settlement Schedule and Payment Calendar*

Description:

- The *final settlement statement* for the *physical market* and virtual *energy* transactions is issued 10 *business days* after Process P5 issues the *preliminary settlement statement*, or 20 *business days* after the *trading day*. With each *final settlement statement*, a *final settlement* data file is also issued, as described in 'Energy/OR/DR Data Files'.
- The *final settlement statement* will include all the information in the *preliminary settlement statement*, and any adjustments resulting from the *notice of disagreement* process. These adjustments will appear as a credit or debit to each *market participant* resulting from *settlement* disagreements that have been resolved prior to the issue date of the *final settlement statements*.

Flow	Source	Target Processes	Frequency
Energy/OR/DR Data Files	Process P5	Market Participant	Issued with corresponding preliminary and final *settlement statement*

Description:

For each *preliminary settlement statement* and *final settlement statement* issued, a corresponding data file will be provided to the *market participant*. Data files are not specific to a charge. The data file includes the following five sub-sections:

1. DAM, PD and RT prices

   Prices will include LMP prices for *energy* and OR, and zonal LMPs for *energy*. Refer to the following tables in Section 6 of this document.

   - Prices that are determined by the DAM calculation engine are detailed in 'DAM Prices and Schedules' in Table 6-1.
   - Prices that are determined by the PD calculation engine as detailed in 'PD Prices and Schedules' in Table 6-1.
   - Prices that are determined by the RT calculation engine as detailed in 'PD Prices and Schedules' in Table 6-1.

2. DAM, PD and RT schedules

   Schedules will include both *energy* and OR schedules in all timeframes. Refer to the following tables in Section 6 of this document.

   - Schedules that are determined by the DAM calculation engine as detailed in 'DAM Prices and Schedules' in Table 6-1.
   - Schedules that are determined by the PD calculation engine are as detailed in 'PD Prices and Schedules' in Table 6-1.
   - Schedules that are determined by the RT calculation engine are as detailed in 'RT Prices and Schedules' in Table 6-1.

3. Offers and bids
    - This includes financial *dispatch data* parameters. Financial *dispatch data* parameters are comprised of *offer* and *bid* data submitted for physical transactions for *energy* and *operating reserve*, and virtual transactions.
    - *Operating reserve offers* can be submitted by dispatchable *generation facilities*, imports and exports and *dispatchable loads*.
    - *Energy offers* can be submitted by dispatchable *generation facilities* and imports. *Energy bids* can be submitted by *dispatchable loads, hourly demand response* resources, and price responsive loads and exports.

    Also included in this section of the *settlement* data file are PSU *offers*, derived price curve offers (DIPC), mitigated financial *dispatch data* and *variable generation offers*. Refer to the following tables in Section 3 of this document for further details and usage description:

    - Table 3-15: Financial Dispatch Data for Physical Transactions Submitted to the DAM
    - Table 3-25: Financial Dispatch Data for Physical Transactions Submitted to Pre-Dispatch
    - Table 3-33: Financial Dispatch Data for Physical Transactions Submitted to the Real-Time Market
4. *Dispatch data* including non-financial *dispatch data* and derived data.

    Refer to the following tables in Section 3 of this document for further details and usage description:

    - For non-financial *dispatch data*, refer to Table 3-9: Non-Financial Hourly and Daily Dispatch Data Used for Settlement.
    - For derived data, refer to Table 3-37: Derived Data for Pseudo-Units.
5. Day-ahead market *physical bilateral contract data* submissions and the *real-time market physical bilateral contract data* submitted by a *selling market participant* including:
    - Day-ahead market *physical bilateral contract data* submissions; and
    - Real-time market *physical bilateral contract data* submissions.

Details of the content of the *settlement statement* files and *settlement* data files will be provided in the update of the Format Specifications Settlement Statement Files and Data Files, IMP_SPEC_0005 to be developed during the implementation phase of the MRP.

Flow	Source	Target Processes	Frequency
TR Market Preliminary Settlement Statements	Process P5	Market Participant	2 *business days* after the *trading day* in accord with the *Settlement Schedule and Payment Calendar*

Description:

- Process P5 issues *preliminary settlement statements* two *business days* after each *trading day* in the financial markets.
- Each *market participant* that has at least one non-zero *settlement amount* for a particular *trading day* will receive a *preliminary settlement statement* for that *trading day*. *Market participants* who were not active on a particular *trading day* will not receive a *preliminary settlement statement* for that day.
- Process P5 generates *preliminary settlement statements* for each *trading day*, but they are issued to *market participants* only on *business days*. This means that on some days, more than one *preliminary settlement statement* is issued.

Flow	Source	Target Processes	Frequency
TR Market Final Settlement Statements	Process P5	Market Participant	6 *business days* after the *trading day* in accord with the *Settlement Schedule and Payment Calendar*
Description: • The *final settlement statement* is issued 4 *business days* after Process P5 issues the *preliminary settlement statement*, or 6 *business days* after the *trading day*. • The *final settlement statement* will include all the information in the *preliminary settlement statement*, and any adjustments resulting from the *notice of disagreement* process and disputes. These adjustments will appear as a credit or debit to each *market participant* resulting from *settlement* disagreements that have been resolved prior to the issue date of the *final settlement statements*.			

6.1.6 Process P6 – Settlement Quality Control

6.1.6.1 Description

The purpose of Process P6 is to confirm the completeness and accuracy of *settlement amount* calculations as provided by Process P1, P2, P3, and P4 and *settlement amounts* to be reflected on *settlement statements* and the data *settlement* data files provided to *market participants* by Process P5.

Process P6 examines *settlement amounts* prior to published the *settlement statement* and *settlement* data file. The amounts examined include:

- Day-ahead and real-time *energy* and *operating reserve settlement amounts*;
- Physical market charges, credits and uplift *settlement amounts*;
- Transmission Rights auction *settlement amounts*; and
- Demand Response market *settlement amounts*.

The following quality control criteria are assessed using a combination of manual and automated verification procedures:

- Quantities used by Process P5 to create *settlement statements* and *settlement* data files should balance with Process P1, P2, P3, P4 output results. This helps in meeting the financial neutrality aspect of *IESO's* current and future market design;
- Only authorized *market participants* should be receiving *settlement statements* and *settlement* data files from Process P5; and
- The *settlement process* operates on the basis of ensuring financial neutrality, specifically:
    - for *hourly market* transactions: the sum of all payments for all *market creditors* will equal the sum of all charges for *market debtors* involved in *hourly market* transactions, for each *trading day* of a *billing period.*
    - for all other transactions: for monthly charges, adjustment charges and payments, the sum of all payments to *market creditors* of those transactions will equal the sum of all charges to *market debtors* of those transactions for each *billing period.*

  An imbalance in financial neutrality may indicate an input or calculation error requiring re-calculation.

In the event that the output from one or more of Processes P1, P2, P3, or P4 fails to meet the above criteria, a re-processing request may be sent back to the appropriate *settlement process* outlining the nature of the problem.

6.1.6.2 Input and Output Data Flows

Table 6-6: Process P6 Input and Output Data Flows

Flow	Source	Target Processes	Frequency
Settlement Amounts	Processes P1,P2, P3, and P4	Process P6	Every *business day*
Description: This data flow includes: • All *settlement amounts* calculated within Processes P1, P2, P3, and P4, which are passed to Process P6. • *Settlement amounts* pertaining to more than one *trading day*, but which will be sub-divided into *settlement statements* for each applicable *trading day*. The organization of balancing groups to ensure financial neutrality are shown in Figure 3-1.			
Flow	**Source**	**Target Processes**	**Frequency**
Re-processing Requests	Process P6	Processes P1, P2, P3 and P4	As required
Description: • In the event that an error is found with the stream of *settlement* amounts, Process P6 will identify the nature of the problems discovered and may trigger a request to re-run Process P1, P2, P3 or P4.			

6.1.7 Process P7 – Notice of Disagreement Process

6.1.7.1 Description

Process P7 closely reflects the current state *notice of disagreement* (NoD) process supported by the *IESO* today with its scope now expanded to include new *settlement charge types* that will appear on *preliminary settlement statements* and *final settlement statements*. Examples of these new *settlement charge types* include those for make-whole payments and any changes to make-whole payments arising out of *IESO*'s Market Power Mitigation process. However, in the case of *settlement amounts* from the *settlement process*, the *market participant* can raise a NoD only after the *settlement amount* has appeared on a *preliminary settlement statement* from Process P5. If a *market participant* submits a NoD and does not agree with the IESO's *notice of disagreement* decision, the *market participant* may then raise a *notice of dispute* in accordance with the process for Validation of Preliminary Settlement Statements set forth in Section 6.6 of the *market rules*.

The adjustments arising from NoDs are typically applied to *final settlement statements* in situations where the NoD is resolved before *final settlement statements* are issued for the affected *trading day*. Otherwise, such adjustments are added to the next available *preliminary settlement statement.* Information from the resolution of NoDs may also be used to support the *settlement process* as it interacts with the Dispute Resolution process.

6.1.7.2 Input and Output Data Flows

Table 6-7: Process P7 Input and Output Data Flows

Flow	Source	Target Processes	Frequency
Notices of Disagreement (NoD)	Market Participant	Process P7	As required

Description:

This data flow will largely have the same characteristics as the NoDs used to support the *physical markets* and financial markets today – but with an expanded scope to support DAM *settlement amounts* and mitigated make-whole payment *settlement amounts* arising from market power mitigation results. All DAM *settlement amounts*, including the *settlement amounts* resulting from the first and second *settlement* under the two-*settlement* system, will be included on a *preliminary settlement statement* and integrated into the existing *notice of disagreement* (NoD) process.

- If a *market participant* disagrees with any item or calculation set forth in a *preliminary settlement statement* that it has received, or considers that there is an omission in such *preliminary settlement statement*, the *market participant* may provide the *IESO* with a *notice of disagreement.*

- A *notice of disagreement* will include the following information:
    - The date of the *preliminary settlement statement* in question;
    - The *dispatch day* in question;
    - The item(s) or omission(s) in question;
    - The reasons for the disagreement;
    - Where applicable, the proposed adjustment to the data used to calculate any relevant *settlement amount* on the *preliminary settlement statement*; and
    - Where applicable, the proposed correction to any calculation of the relevant *settlement amount* on the *preliminary settlement statement*.

Each *market participant* has 4 *business days* in which to notify the *IESO* of errors or omissions in the *preliminary settlement statement* for the *physical markets*. For the financial market, each *market participant* has 2 *business days* in which to notify the *IESO* of errors or omissions.

Flow	Source	Target Processes	Frequency
NoD Decisions and Information	Process P7	Market Participant and Dispute Resolution	As required

Description:

The *IESO* uses the information provided in and with a *notice of disagreement*, and any other information available to the *IESO*, to investigate the subject matter of the disagreement. Based on the results of the investigation, the *IESO* will determine the appropriate actions and, after informing the *market participant* of its intended actions and providing them with an opportunity to respond, and take the appropriate action as detailed in the *market rules*.

All critical information pertaining to the outcome of a *notice of disagreement* may be required by the Dispute Resolution process in the event that a dispute is raised over the same matter in future. To support the *settlement process* under such circumstances, the following information about a particular NoD will be sent to Dispute Resolution process:

- The original NoD filed;

- Supporting information exchanged between the *IESO* and the *market participant* concerning the NoD in question; and
- Record of any NoD adjustments sent from Process P7 to Process P5.

Flow	Source	Target Processes	Frequency
Dispute Resolution Outcome	Dispute Resolution	Process P8	As required

Description:

- If a *market participant* does not agree with the *notice of disagreement* decision, the *market participant* may also raise a *notice of dispute* through the Dispute Resolution process.
- The Dispute Resolution process communicates with *notice of disagreement* process to exchange notice of dispute data.

Flow	Source	Target Processes	Frequency
NoD Resolution	Process P7	Process P5	As required

Description:

All critical information pertaining to the resolution of a *notice of disagreement* may be of relevance in the event that a *notice of dispute* is raised over the same matter again in future. To support the *settlement process* under such circumstances, the following information about a particular NoD will be used to support Process P5:

- The original NoD filed;
- Feedback between the *IESO* and the *market participant* concerning the NoD in question; and
- Record of any NoD adjustments sent from Process P7 to Process P5.

6.1.8 Process P8 – Settlement Recalculation

6.1.8.1 Description

This process effectively re-creates any calculations produced by Process P1, P2, P3, or P4 using:

- original *settlement* data from the affected *trading day*; and
- any adjustments to such data as may be ordered by the Dispute Resolution process.

6.1.8.2 Input and Output Data Flows

Table 6-8: Process P8 Input and Output Data Flows

Flow	Source	Target Processes	Frequency
Settlement Data	Settlement Data Archive	Process P8	As required

Description:

This data flow is required in the event that a *settlement* recalculation is necessary to resolve a dispute and the age of the necessary supporting *settlement* information has exceeded the retention period in the *settlement* calculation on-line storage solution and has therefore been archived in an offline system.

This data flow:			
• Includes data either for a *preliminary settlement statement* or a *final settlement statement*, and the corresponding *settlement* data files; and • May contain *settlement amounts* pertaining to more than one *trading day*, but which will be sub-divided into *settlement statements* for each applicable *trading day*.			
Flow	**Source**	**Target Processes**	**Frequency**
Dispute Resolution Outcome	Dispute Resolution	Process P8	As required
Description: If a *market participant* does not agree with the *notice of disagreement* decision, they may also elect or choose to raise a *notice of dispute* through the Dispute Resolution process. • In the case of *settlement* disputes, the outcome decision rendered by the dispute resolution process can take either of the following two forms: 1. An order for a *settlement* statement re-calculation; or 2. A dollar value adjustment to be applied. • This data flow will communicate the nature and size of dispute resolution outcomes to the Settlement Recalculation process.			
Flow	**Source**	**Target Processes**	**Frequency**
Re-calculation Adjustments	Process P8	Process P5	As required
Description: • Adjustments arising from the *settlement* re-calculation process will typically resolve down to a dollar amount applicable to the next available *preliminary settlement statement*. • This data flow will include the origin and dollar value of the adjustment.			

6.2 Internal Process Impacts

The internal processes currently used for settlements will continue to have relevance in the future *real-time market* and the day-ahead market.

Internal *IESO* processes related to Market Settlement include:

- Settle Market and Programs; and
- Calculate Corrective Settlement Details.

The above internal processes interact with various *IESO* processes as illustrated in Section 6.1. Some changes to the Market Settlement process under the market renewal program will impact other internal *IESO* processes. This impact will be contingent upon the tools of the future day-ahead market and real-time market which will be developed during the next phases of the project.

Changes or additions to internal *IESO* processes are for internal *IESO* use as documented in Appendix C, and are not included in the public version of this document. Appendix C details the impacts to internal processes in terms of existing processes that support the new market requirements, existing activities that need to be updated, and process and information models that may need to be updated to support the future market.

– End of Section –

Appendix A: Market Participant Interfaces

Market Participant Interfaces

The following table provides a description of the changes and additions to *IESO* technical interfaces with *market participant*s that may be required to support the Market Settlement process design of the future day-ahead market and *real-time market*.

Table A-1: Impacts to Market Participant Interfaces

MP Interface Name	Interface Type	Description of Impact
IESO Reports Site (http://reports.ieso.ca/) and Application Programming Interface (API)	Web Client	No changes to the platform, but the contents of private and public market settlement reports will be updated where applicable. Contents of *settlement* data files and invoices will include new *charge types.*
Online IESO (https://online.ieso.ca/suite/)	Web Client	No changes to the platform, but the following Online IESO applications will be updated to accommodate new *charge types*: • Notice of Disagreement • Settlement Claim Submission

Market Settlement Forms

The following table provides a description of the changes and additions to *IESO* forms with *market participant*s that may be required to support the Market Settlement process design of the future day-ahead market and *real-time market*.

Table A-1: Market Settlement Forms

Form Name	Form Number	Description of Impact
Administrative Pricing Event Correction	IMO_FORM_1549	Obsolete. Not required in future market.
Notice of Dispute	IMO_FORM_1001	No changes required.
Fuel Cost Compensation	IESO_FORM_1654	Obsolete. Not required in future market.
Application for Designation of a Facility for Generation Station Service Rebate	IMO_FORM_1419	No changes required.
Declaration of Designated Consumer	IMO_FORM_1507	No changes required.

– End of Section –

Appendix B: Internal-Facing Procedural Requirements *[Internal only]*

This section is confidential to the IESO.

Appendix C: IESO Internal Business Process and Information Requirements *[Internal only]*

This section is confidential to the IESO.

Appendix D: Settlement Amounts

The implementation of MRP will introduce new *settlement amounts.* Some existing *settlement amounts* will be affected by the implementation of the DAM, and in these instances, those *settlement amounts* may be amended, replaced entirely, or will be retired under MRP. The new MRP *settlement amounts*, which will replace current *settlement amounts*, will take into account both day-ahead market and *real-time market* activity. The tables that follow summarize the impact of MRP on existing *settlement amounts* and introduce the new *settlement amounts*.

There will be a period of time where *market participants* will continue to see existing *settlement amounts* on their *settlement statements* that will not be required in the future market as the *IESO* transitions from the current market to the future market.

New Settlement Amounts

The following new *settlement amounts* will be calculated as part of the two-*settlement* system and are discussed in Section 3.6 – Day-Ahead and Real-Time Energy and Operating Reserve Settlement.

Table D-1: New Settlement Amounts Under Two-Settlement System

Name	Acronym	Section Reference
Hourly Physical Transaction Settlement Amount {1}	HPTSA{1}	3.6.1
Hourly Physical Transaction Settlement Amount {2}	HPTSA{2}	3.6.2
Hourly Physical Transaction Settlement Amount – Non-dispatchable Load	HPTSA_NDL	3.6.3
Hourly Virtual Transaction Settlement Amount {1}	HVTSA{1}	3.6.1
Hourly Virtual Transaction Settlement Amount {2}	HVTSA{2}	3.6.2
Hourly Operating Reserve Settlement Amount {1}	HORSA{1}	3.6.1
Hourly Operating Reserve Settlement Amount {2}	HORSA{2}	3.6.2
DAM Operating Reserve Uplift	DORU	3.6.2

The following new *settlement amounts* will be calculated outside of the two-*settlement* system and are discussed in Section 3.7 – Market Charges, Credits and Uplifts.

Table D-2: New Settlement Amounts Outside of the Two-Settlement System

Name	Acronym	Section Reference
Day-Ahead Market Make-Whole Payment	DAM_MWP	3.7.1
Day-Ahead Market Generator Offer Guarantee	DAM_GOG	3.7.2
Day-Ahead Market Make-Whole Payment Uplift	DAM_MWPU	3.7.3
Day-Ahead Market Reliability Scheduling Uplift	DRSU	3.7.4
Real-Time Make-Whole Payment	RT_MWP	3.7.5
Real-Time Make-Whole Payment Uplift	RT_MWPU	3.7.6
DAM Balancing Credit	DAM_BC	3.7.7

Name	Acronym	Section Reference
DAM Balancing Credit Uplift	DAM_BCU	3.7.8
Real-Time Generator Offer Guarantee	RT_GOG	3.7.9
Real-Time Generator Offer Guarantee Uplift	RT_GOGU	3.7.10
Generator Failure Charge – Market Price Component	GFC_MPC	3.7.11
Generator Failure Charge – Guarantee Cost Component	GFC_GCC	3.7.11
Generator Failure Charge – Market Price Component Uplift	GFC_MPCU	3.7.12
Generator Failure Charge – Guarantee Cost Component Uplift	GFC_GCCU	3.7.13
Congestion Rent and Loss Residuals Disbursement	CRLRD	3.7.14
Real-Time Operating Reserve Shortfall Debit	RT_ORSD	3.7.16
Real-Time Operating Reserve Shortfall Debit Uplift	RT_ORSDU	3.7.16
Real-Time Intertie Failure Charge	RT_INFC	3.7.16
Real-Time Intertie Failure Charge Uplift	RT_INFCU	3.7.16
Real-Time Intertie Offer Guarantee	RT_IOG	3.7.16
Real-Time Intertie Offer Guarantee Uplift	RT_IOGU	3.7.16
Real-Time Ramp-Down Settlement Amount	RT_RDSA	3.7.16
Real-Time Ramp-Down Settlement Amount Uplift	RT_RDSAU	3.7.16
DAM Reference Level Settlement Charge	DAM_RLSC	3.13.2
Real-Time Reference Level Settlement Charge	RT_RLSC	3.13.2
Reference Level Settlement Charge Uplift	RLSCU	3.13.3
Ex-Post Mitigation for Physical Withholding Settlement Charge	EXP_PWSC	3.13.4
Ex-Post Mitigation for Economic Withholding on Uncompetitive Interties Settlement Charge	EXP_EWSC	3.13.4
Ex-Post Mitigation Settlement Charge Uplift	EXP_MSCU	3.13.5

Existing IESO-Administered Markets Settlement Amounts

The *settlement amounts* determined for the following *IESO-administered markets charge types* are not impacted by MRP. The calculation of the *settlement amount* under each of these *charge types* will continue in their present form and usage after implementation of MRP.

Table D-3: Existing IESO-Administered Markets Charge Types – Not Impacted by MRP

Count	Charge Type Number	Charge Type Name
1	114	Outage Cancellation / Deferral Settlement Credit
2	115	Unrecoverable Testing Costs Credit
3	116	Tieline Maintenance Reliability Credit
4	118	Emergency Energy Rebate
5	120	Local Market Power Debit
6	123	MACD Enforcement Activity Amount
7	164	Outage Cancellation / Deferral Debit
8	165	Unrecoverable Testing Costs Debit
9	166	Tieline Maintenance Reliability Debit
10	167	Emergency Energy Debit
11	169	Station Service Reimbursement Debit
12	170	Local Market Power Rebate
13	410	IESO-Controlled Grid Special Operations Credit
14	460	IESO-Controlled Grid Special Operations Debit
15	700	Dispute Resolution Settlement Amount
16	750	Dispute Resolution Balancing Amount (IESO)
17	751	Dispute Resolution Board Service Debit
18	850	Market Participant Default Settlement Debit
19	851	Market Participant Default Interest Debit
20	900	GST/HST Credit
21	950	GST/HST Debit
22	1314	Demand Response Capacity Obligation - Availability Payment
23	1315	Demand Response Capacity Obligation - Availability Charge
24	1316	Demand Response Capacity Obligation - Administration Charge
25	1317	Demand Response Capacity Obligation - Dispatch Charge
26	1318	Demand Response Capacity Obligation - Capacity Charge
27	1319	Demand Response Capacity Obligation - Buy-Out Charge
28	1350	Capacity Based Recovery Amount for Class A Loads
29	1351	Capacity Based Recovery Amount for Class B Loads
30	1750	Dispute Resolution Balancing Amount (Market)
31	9920	Adjustment Account Debit
32	9980	Smart Metering Charge
33	9990	IESO Administration Charge
34	9996	Recovery of Costs

The *settlement amounts* determined for the following *IESO-administered markets charge types* will be amended due to MRP. Refer to Section 3.4 – Impact on Current Settlement Amount Calculations for details.

Table D-4: Existing IESO-Administered Markets Charge Types – Amended Due to MRP

Count	Charge Type Number	Charge Type Name
1	119	Station Service Reimbursement Credit

The *settlement amounts* determined for the following *IESO-administered markets charge types* are impacted by MRP. Upon implementation of MRP, these *charge types* will be retired. There will be a period of time where *market participants* will continue to see these *charge types* on their *settlement statements* as the *IESO* transitions from the current market to the future market. Refer to Section 3.4 – Impact on Current Settlement Amount Calculations for details.

Table D-5: Existing IESO-Administered Markets Charge Types – Impacted by MRP

Count	Charge Type Number	Charge Type Name
1	100	Net Energy Market Settlement for Generators and Dispatchable Load
2	101	Net Energy Market Settlement for Non-dispatchable Load
3	105	Congestion Management Settlement Credit for Energy
4	106	Congestion Management Settlement Credit for 10 Minute Spinning Reserve
5	107	Congestion Management Settlement Credit for 10 Minute Non-spinning Reserve
6	108	Congestion Management Settlement Credit for 30 Minute Operating Reserve
7	113	Additional Compensation for Administrative Pricing Credit
8	122	Ramp-Down Settlement Amount
9	124	SEAL CMSC Amount
10	133	Generation Cost Guarantee Payment
11	135	Real-time Import Failure Charge
12	136	Real-time Export Failure Charge
13	150	Net Energy Market Settlement Uplift
14	155	Congestion Management Settlement Uplift
15	163	Additional Compensation for Administrative Pricing Debit
16	183	Generation Cost Guarantee Recovery Debit
17	186	Intertie Failure Charge Rebate
18	200	10-Minute Spinning Reserve Market Settlement Credit
19	201	10-Minute Spinning Reserve Market Shortfall Rebate
20	202	10-Minute Non-spinning Reserve Market Settlement Credit
21	203	10-Minute Non-spinning Reserve Market Shortfall Rebate
22	204	30-Minute Operating Reserve Market Settlement Credit
23	205	30-Minute Operating Reserve Market Shortfall Rebate
24	250	10-Minute Spinning Market Reserve Hourly Uplift
25	251	10-Minute Spinning Market Reserve Shortfall Debit
26	252	10-Minute Non-spinning Market Reserve Hourly Uplift
27	253	10-Minute Non-spinning Market Reserve Shortfall Debit
28	254	30-Minute Operating Reserve Market Hourly Uplift
29	255	30-Minute Operating Reserve Market Shortfall Debit

Count	Charge Type Number	Charge Type Name
30	1050	Self-Induced Dispatchable Load CMSC Clawback
31	1051	Ramp-Down CMSC Clawback
32	1131	Intertie Offer Guarantee Settlement Credit
33	1134	Day-Ahead Linked Wheel Failure Charge
34	1135	Day-Ahead Import Failure Charge
35	1136	Day-Ahead Export Failure Charge
36	1138	Day-Ahead Fuel Cost Compensation Credit
37	1188	Day-Ahead Fuel Cost Compensation Debit
38	1500	Day-Ahead Production Cost Guarantee Payment - Component 1 and Component 1 Clawback
39	1501	Day-Ahead Production Cost Guarantee Payment - Component 2
40	1502	Day-Ahead Production Cost Guarantee Payment - Component 3 and Component 3 Clawback
41	1503	Day-Ahead Production Cost Guarantee Payment - Component 4
42	1504	Day-Ahead Production Cost Guarantee Payment - Component 5
43	1505	Day-Ahead Production Cost Guarantee Reversal
44	1510	Day-Ahead Generator Withdrawal Charge
45	1550	Day-Ahead Production Cost Guarantee Recovery Debit
46	1560	Day-Ahead Generator Withdrawal Rebate

Existing Transmission Rights Market Settlement Amounts

As discussed in Section 3.4 – Impact on Current Market Settlement Amount Calculations and Section 3.7.15 – Transmission Rights, *TR market settlements* will shift from real-time to day-ahead. Upon completion of the TR Market Review, *settlement amounts* will be determined for the future market.

Table D-6: Existing Transmission Rights Market Charge Types

Count	Charge Type Number	Charge Type Name
1	52	Transmission Rights Auction Settlement Debit
2	102	TR Clearing Account Credit
3	103	Transmission Charge Reduction Fund
4	104	Transmission Rights Settlement Credit
5	168	TR Market Shortfall Debit

Existing Ancillary Service Settlement Amounts

The *settlement amounts* determined for the following *ancillary service* and other out-of-market contract *charge types* will be reviewed in the implementation phase of MRP to identify what amendments may be required as a result of MRP. The *settlement process* will directly incorporate any amendments into the *settlement* calculations.

Table D-7: Existing Ancillary Service Charge Types

Count	Charge Type Number	Charge Type Name
1	400	Black Start Capability Settlement Credit
2	404	Regulation Service Settlement Credit
3	450	Black Start Capability Settlement Debit
4	451	Hourly Reactive Support and Voltage Control Settlement Debit
5	452	Monthly Reactive Support and Voltage Control Settlement Debit
6	454	Regulation Service Settlement Debit
7	500	Must-Run Contract Settlement Credit
8	550	Must-Run Contract Settlement Debit
9	1401	Incremental Loss Settlement Credit
10	1403	Speed no-load Settlement Credit
11	1404	Condense Unit Start-up and OM&A Settlement Credit
12	1405	Hourly Condense Energy Costs Settlement Credit
13	1406	Monthly Condense Energy Costs Settlement Credit
14	1407	Condense Transmission Tariff Reimbursement Settlement Credit
15	1408	Condense Availability Cost Settlement Credit
16	1417	Daily Condense Energy Costs Settlement Credit
17	1418	Biomass Non-Utility Generation Contracts Settlement Amount
18	1419	Energy from Waste (EFW) Contracts Settlement Amount
19	1421	Capacity Agreement Settlement Credit
20	1422	Capacity Agreement Penalty Settlement Amount
21	1423	Energy Sales Agreement Settlement Credit
22	1424	Energy Sales Agreement Penalty Settlement Amount
23	1451	Incremental Loss Offset Settlement Amount
24	1468	Biomass Non-Utility Generation Contracts Balancing Amount
25	1469	Energy from Waste (EFW) Contracts Balancing Amount
26	1471	Capacity Agreement Balancing Amount
27	1472	Capacity Agreement Penalty Balancing Amount
28	1473	Energy Sales Agreement Balancing Amount
29	1474	Energy Sales Agreement Penalty Balancing Amount
30	1600	Forecasting Service Settlement Amount
31	1650	Forecasting Service Balancing Amount
32	2404	Supplemental Reactive Support and Voltage Control Service Settlement Credit

Existing Legislation-Related Settlement Amounts

The *settlement amounts* determined for the following legislation-related *charge types* are not impacted by MRP. The calculation of the *settlement amount* under each of these *charge types* will continue in their present form and usage after implementation of MRP.

Table D-8: Legislation-Related Charge Types – Not Impacted by MRP

Count	Charge Type Number	Charge Type Name
1	600	Network Service Credit
2	601	Line Connection Service Credit
3	602	Transformation Connection Service Credit
4	603	Export Transmission Service Credit
5	650	Network Service Charge
6	651	Line Connection Service Charge
7	652	Transformation Connection Service Charge
8	653	Export Transmission Service Charge

The *settlement amounts* determined for the following legislation-related *charge types* will be reviewed in the implementation phase of MRP. The *IESO*, in collaboration with the appropriate regulatory bodies will review relevant legislation and regulation to identify what amendments may be required as a result of MRP. The *settlement process* will directly incorporate any amendments into the *settlement* calculations.

Table D-9: Legislation-Related Charge Types - Impacted by MRP

Count	Charge Type Number	Charge Type Name
1	121	Northern Industrial Electricity Rate Program Settlement Amount
2	142	Regulated Price Plan Settlement Amount
3	143	NUG Contract Adjustment Settlement Amount
4	144	Regulated Nuclear Generation Adjustment Amount
5	145	Regulated Hydroelectric Generation Adjustment Amount
6	147	Class A Global Adjustment Settlement Amount
7	148	Class B Global Adjustment Settlement Amount
8	171	Northern Industrial Electricity Rate Program Balancing Amount
9	192	Regulated Price Plan Balancing Amount
10	193	NUG Contract Adjustment Balancing Amount
11	194	Regulated Nuclear Generation Balancing Amount
12	195	Regulated Hydroelectric Generation Balancing Amount
13	196	Global Adjustment Balancing Amount
14	197	Global Adjustment-Special Programs Balancing Amount
15	703	Rural Rate Settlement Credit
16	705	Ontario Fair Hydro Plan First Nations On-Reserve Delivery Amount
17	706	Ontario Fair Hydro Plan Distribution Rate Protection Amount
18	753	Rural Rate Settlement Charge
19	755	MOE - Ontario Fair Hydro Plan First Nations On-Reserve Delivery Balancing Amount
20	756	MOE - Ontario Fair Hydro Plan Distribution Rate Protection Balancing Amount

Count	Charge Type Number	Charge Type Name
21	1148	GA Energy Storage Injection Reimbursement
22	1400	OPA Contract Adjustment Settlement Amount
23	1410	Renewable Energy Standard Offer Program Settlement Amount
24	1412	Feed-In Tariff Program Settlement Amount
25	1413	Renewable Generation Connection - Monthly Compensation Amount Settlement Credit
26	1414	Hydroelectric Contract Initiative Settlement Amount
27	1416	Conservation and Demand Management-Compensation Settlement Credit
28	1420	Ontario Electricity Support Program Settlement Amount
29	1425	Hydroelectric Standard Offer Program Settlement Amount
30	1450	OPA Contract Adjustment Balancing Amount
31	1457	Ontario Electricity Rebate Balancing Amount
32	1460	Renewable Energy Standard Offer Program Balancing Amount
33	1462	Feed-In Tariff Balancing Amount
34	1463	Renewable Generation Connection - Monthly Compensation Amount Settlement Debit
35	1464	Hydroelectric Contract Initiative Balancing Amount
36	1466	Conservation and Demand Management-Compensation Balancing Amount
37	1475	Hydroelectric Standard Offer Program Balancing Amount
38	1476	Global Adjustment Mechanism Labour Balancing Amount
39	1753	MOE - Rural and Remote Settlement Debit
40	2148	Class B GA Prior Period Correction Settlement Amount
41	2470	MOE - Ontario Electricity Support Program Balancing Amount
42	9983	Ontario Electricity Rebate Settlement Amount

References

Document Name	Document ID
MRP Detailed Design: Overview	DES-16
MRP Detailed Design: Prudential Security	DES-17
MRP Detailed Design: Facility Registration	DES-19
MRP Detailed Design: Grid and Market Operations Integration	DES-22
MRP Detailed Design: Day-Ahead Market Calculation Engine	DES-23
MRP Detailed Design: Pre-Dispatch Calculation Engine	DES-24
MRP Detailed Design: Real-Time Calculation Engine	DES-25
MRP Detailed Design: Market Power Mitigation	DES-26
MRP Detailed Design: Publishing and Reporting Market Information	DES-27
MRP Detailed Design: Market Settlement	DES-28
IESO Charge Types and Equations	IMP_LST_0001
Market Manual 5: Settlements, Part 5.0 - Settlements Overview	MDP_MAN_0005
Market Manual 5: Settlements, Part 5.1 - Settlement Schedule and Payments Calendars (SSPCs)	MDP_PRO_0031
Market Manual 5: Settlements, Part 5.1- Settlement Schedule and Payments Calendars (SSPCs)	MDP_PRO_0031
Market Manual 5: Settlements, Part 5.3 - Submission of Physical Bilateral Contract Data	MDP_PRO_0034
Market Manual 5: Settlements, Part 5.3 - Submission of Physical Bilateral Contract Data	MDP_PRO_0034
Market Manual 5: Settlements, Part 5.5 - Physical Markets Settlement Statements	MDP_PRO_0033
Market Manual 5: Settlements, Part 5.5 - Physical Markets Settlement Statements	MDP_PRO_0033
Market Manual 5: Settlements, Part 5.7 - Financial Markets Settlement Statements	MDP_PRO_0046
List of Resources for Physical Bilateral Contracts	IMO_PBCL_0001
Market Manual 4 Market Operations, Part 4.6 - Real-Time Generation Cost Guarantee Program	PRO-324
Market Manual 6: Participant Technical Reference Manual	IMO_MAN_0024

Document Name	Document ID
Market Manual 9: Day-Ahead Commitment Process, Part 9.5 - Settlement for the Day-Ahead Commitment Process	IESO_MAN_0080
Format Specifications for Settlement Statement Files and Data Files	IMP_SPEC_0005
File Format Specifications for Participant Transmission Tariff Data Files	IMP_SPEC_0006
File Format Specifications for the Transmitter Transmission Tariff Data File	IMP_SPEC_0007
File Format Specifications for Transmitter Reconciliation Data File	IMP_SPEC_0008
Transmission Tariff Peak System Demand Data Report	IMP_REP_0016
Notice of Dispute	IESO_FORM_1001
Administrative Pricing Event Correction	IESO_FORM_1549
Reduced Debt Retirement Charge (DRC) Certification	IESO_FORM_1438
Fuel Cost Compensation (Under 'Day-Ahead Commitment')	IESO_FORM_1654
Application for Designation of a Facility for Generation Station Service Rebate	IESO_FORM_1419
Declaration of Designated Consumer	IESO_FORM_1507
Guide to Settlement Claims and Data Submissions via Online IESO	ONLSF_GUIDE_EXT
Training Materials: Settlement Statements and Invoices	n/a

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