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MARKET MANUAL

Market Manual 9: Day-Ahead Commitment Process

Part 9.5: Settlement for the Day-Ahead Commitment Process

Issue 3.0

This document provides guidance to Market Participants on the procedures associated with the interaction of the Day-Ahead Commitment Process with Settlements.

Disclaimer

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Issue	Reason for Issue	Date
1.0	Issued in advance of Baseline 26.1 for the implementation of EDAC	October 12, 2011
2.0	Issue released for Baseline 29.0	March 6, 2013
3.0	Issue released for Baseline 33.1	June 3, 2015

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Reference (Paragraph and Section)	Description of Change
Section 9	Table 9-1: Added column to identify scenarios under which the DA-IOG Component #2 is calculated

1. Market Manuals

The *market manuals* consolidate the market procedures and associated forms, standards, and policies that define certain elements relating to the operation of the *IESO-administered markets*. Market procedures provide more detailed descriptions of the requirements for various activities than is specified in the "Market Rules". Where there is a discrepancy between the requirements in a document within a *market manual* and the *market rules*, the *market rules* shall prevail. Standards and policies appended to, or referenced in, these procedures provide a supporting framework.

– End of Section –

2. About this Manual

This document, "Part 9.5: Settlement for the Day-Ahead Commitment Process", is part of *Market Manual* Volume 9 (a.k.a., the "Day-Ahead Commitment Process Manual").

The "Day-Ahead Commitment Process Manual" is the collection of documents related to the Day-Ahead Commitment Process (DACP), and consists of the following document set**:**

Table 2-1: Table of Contents—Market Manual 9

Document ID	Part No.	Name of Procedure Document
IESO_MAN_0041	9.0	Day Ahead Commitment Process Overview
IESO_MAN_0076	9.1	Submitting Registration Data for the Day Ahead Commitment Process
IESO_MAN_0077	9.2	Submitting Operational and Market Data for the Day Ahead Commitment Process
IESO_MAN_0078	9.3	Operation of the Day Ahead Commitment Process
IESO_MAN_0079	9.4	Real-Time Integration of the Day Ahead Commitment Process
IESO_MAN_0080	9.5	Settlement for the Day Ahead Commitment Process

2.1 Conventions

The *market manual* standard conventions are as defined in "Part 9.0: Day-Ahead Commitment Process", section '2.4 Conventions'.

– End of Section –

3. Introduction

3.1 Purpose

This document provides *market participants* with the procedures associated with the interaction of the Day-Ahead Commitment Process (DACP) with *Settlements*. The document reflects the requirements set out in the *market rules* and applicable *IESO* policies and standards.

3.2 Scope

This *market manual* describes the *settlements* procedures as they relate to the DACP. *Settlement* of DACP related items in the *IESO-administered markets* consists of:

- Settling any guarantees derived from the DACP:
    - Day-Ahead Production Cost Guarantees (DA-PCG), and the related Fuel Cost Compensation (FCC) for de-committed *generators*, and
    - Day-Ahead Intertie Offer Guarantees (DA-IOG) and the related IOG Offset process.
- Settling any charges or rebates applied to *generators*, imports, and exports committed in the DACP that do not deliver expected quantities in the *real-time market*:
    - Day-Ahead Generator Withdrawal Charge (DA-GWC)
    - Day-Ahead Fuel Cost Compensation (DA-FCC)
    - Day-Ahead Import Failure Charge (DA-IFC)
    - Day-Ahead Export Failure Charge (DA-EFC)
    - Day-Ahead Linked Wheel Failure Charge (DA-LWFC)

3.3 Contact Information

Inquiries regarding DACP settlements should be directed to the *IESO* Customer Relations Department. Contact information is available from the "Contact Us" link in the *IESO* website (www.ieso.ca).

– End of Section –

4. Derived Interval Price Curve

This section applies only to *generation units* associated to combined-cycle plant using the *pseudo unit* (*PSU*) model in DACP. If you operate a combined-cycle plant, you can opt to be modeled as a collection of *PSU*s where each *PSU* represents the capacity of a single combustion turbine (CT) and a portion of the capacity of the steam turbine (ST) associated with the plant.

All day-ahead offers are submitted by you on a *PSU* basis and a day-ahead constrained schedule is determined for each *PSU* which then is translated into CT and ST schedules. In real-time, your combined-cycle plants will continue to be offered and dispatched on a physical unit (PU) level. All DACP settlement amounts are calculated by us on a *registered facility* basis, so the day-ahead *PSU offers* will be translated into day ahead *registered facility* equivalents before the *settlement* calculations takes place. The PU *offer* curve that we construct by translating your *PSU offers* is called the Derived Interval Price Curve (DIPC).

4.1 How the DIPC is Constructed

We construct the Derived Interval Price Curve (DIPC) for day-ahead scheduled *generation facilities* under the following circumstances:

- You indicate your desire to be modeled as a *PSU* through the registration process,
- You are an eligible DA-PCG resource as determined through the *IESO* registration process, and
- Your *generation unit* is included in the *schedule of record*.

The *IESO*:

1. Determines the portions of the day-ahead *PSU* schedule in each of the three *PSU* operating regions: MLP Region Range, Dispatchable Region Range, and Duct Firing Region Range.
2. Removes derated MWs from the top of the Dispatchable Region Range *PSU* offers for any derates you have for the associated CT. This is done through a collapse of the *price quantity pairs* attributed to those derated MWs. Refer to ‘Appendix A: *PSU* and Derates’ for more information on how derates impact *PSU*s.
3. Constructs the DIPC for each of the CTs for every interval with a day-ahead schedule.
4. Determines for the ST, the set of *PSU offer* curves to be included in the DIPC. For each *PSU*, the associated ST price curve will be included in the DIPC if:
    - Your ST is withdrawn in real-time, or
    - Your ST is not withdrawn in real-time and your associated CT is injecting for the interval.

    Otherwise, if your ST is not withdrawn in real-time and your associated CT is not injecting for the interval, then the associated ST price curve will not be included in the DIPC.
5. Constructs the DIPC for the ST by combining the individual ST Price curves of included *PSU*s into a single price curve. See ‘Appendix B: DIPC Formulation’ for a detailed description of how we calculate DIPC.

– End of Section –

5. Day-Ahead Production Cost Guarantee

The Day-Ahead Production Cost Guarantee (DA-PCG) allows you to recover certain costs called "day-ahead costs" for eligible *generators* committed by the DACP. The guarantee applies if you have not recovered these costs through other market revenues.

Your acceptance of the DA-PCG is automatic. You cannot call to reject the guarantee as a means of removing constraints on your resources.

Your *generation unit* will be scheduled and dispatched to a quantity no lower than its *minimum loading point* (MLP), unless we approve a withdrawal request or require de-commitment for *reliability*.

5.1 How the DA-PCG is Settled

1. To receive the DA-PCG:
    - You must be included in the *schedule of record*,
    - Your *generation unit* must:
        - Not have a withdrawal[1] within your control for any hour in the DACP start event, and
        - Have its *generator* breaker closed by the start of the first interval of the first DACP scheduled hour.

        Note: For *settlement* purposes, the breaker close for the *generation unit* is identified by using *revenue meter* data. A *generation unit* is considered to have closed its breaker when *revenue meter* data indicates a value greater than zero that is sustained for four consecutive intervals.
2. We will calculate the DA-PCG for each DACP start event individually. A DACP start event is defined as the period from the first hour with a day-ahead schedule to the last consecutive hour with a day-ahead schedule.
3. If your *generation unit* is scheduled in DACP to start more than once in the day and you continue to generate in real-time without shutting down in the hours between the DACP start events, then:
    - Your *generation unit* is not eligible for the DA-PCG for the hours not scheduled in the DACP.
    - Your *generation unit* is eligible for the DA-PCG for all hours committed in the DACP (i.e., you are eligible to recover as-offered start-up costs and speed-no-load costs even though your *generation unit* did not shut down in real-time between scheduled DACP starts).

[1] This is for withdrawals within the *market participant's* control as defined in Section 7 Day-Ahead Generator Withdrawal Charge.

4. For *reliability* reasons, we may de-commit your *generation unit* before it has completed its day-ahead schedule (see section 6 'Day-Ahead Fuel Cost Compensation due to De-commitment'). If this happens, you are still eligible for guarantee payments for costs incurred before de-commitment.
5. If you withdraw your *generation unit* before it has completed its day-ahead schedule, you may or may not be eligible for the DA-PCG as follows:
   - If it is determined that the withdrawal was not in your control, you will be eligible for the DA-PCG for the hours not withdrawn.
   - If it is determined that the withdrawal was within your control, you will not be eligible for the DA-PCG in any hour in the DACP start event. You will also be assessed the Day-Ahead Generator Withdrawal Charge (DA-GWC).

   Note: Refer to section 7 'Day-Ahead Generator Withdrawal Charge' for more information on withdrawals.
6. In calculating your *day-ahead costs*, we use the values submitted by you through your three-part *offers*. The MLP and *minimum generation block run-time* (MGBRT) that are registered in our *facility* registration database effective for the date of the *start-up time* will be superseded by the Daily Generation Data (DGD) MLP and DGD MGBRT.
7. We will calculate the total *day-ahead costs* as the sum of the following costs:
   - The submitted three-part *energy offers*:
     - *Start-up cost*: cost to bring your *generation unit* up to MLP,
     - Minimum generation cost: speed no load cost plus incremental *energy offer* up to MLP, and
     - Incremental *energy*: *energy offers* for entire operating range of *generator* above MLP.
   - Cost of arranging the delivery for the portion of the *schedule of record* not implemented in the real-time as a result of economic selection (where the real-time *offer* price is less than the day-ahead *offer* price).[2,3]
8. If your *MGBRT* will require your *generation unit* to run beyond the end of the day, you may submit *offers* with escalating start-up *offers* at the end of the DACP day to receive *start-up cost*, *speed no load* and incremental *energy* to the MLP within that day.

   Note: As part of the three-part *offers* you may submit different *start-up costs* for each hour in the DACP day, and not exclusively for the hours at the end of the day to reflect your costs for completing *MGBRT* in the next day.
9. If your *MGBRT* will require your *generation unit* to run beyond the end of the day, the DA-PCG for the hours in the first day will be calculated independent of the hours in the second day. In other words, we will treat these as two individual DACP start events for the purposes of calculating the DA-PCG.

[2] If you are committed to run in the DACP and do not get scheduled for your full day-ahead schedule in real-time, your guarantee payment will be increased to account for any costs represented by lower real-time *offers* for that portion of *energy* not scheduled in real-time.
[3] This is limited to the Operating Capacity of your *generation unit*. Refer to 'Appendix D Determining OPCAP OPCAP' for details on how the Operating Capacity is determined.

10. There are three possible variations of the DA-PCG *settlement* calculation:

    - Variant 1 is the standard DA-PCG *settlement* calculation and applies where the start was scheduled in the current day, excluding Variant 3.
    - Variant 2 of the DA-PCG calculation is used when your *generation unit* is in operation in HE 24 (i.e., identified by the online status) of the previous DACP *dispatch day* and in HE1 of the current DACP *dispatch day* in order to complete its MGBRT. Your start-up cost and your minimum generation costs (speed-no-load and incremental *energy offers* up to your MLP) will not be accounted for in the current DACP *dispatch day's* DA-PCG *settlement* calculation.
    - Variant 3 of the DA-PCG calculation is used when your *generation unit* is in operation in HE 24 (i.e., identified by the online status) of the previous DACP *dispatch day* and in HE1 of the current DACP *dispatch day* and has completed its MGBRT in the previous *dispatch day*. Your start-up cost will not be accounted for in the current DACP *dispatch day's* DA-PCG *settlement* calculation.

11. We determine the online status of your *generation unit* by your Initial Hours of Operation (IHO). The IHO is the number of consecutive hours your *generation unit* is in operation at the end of the current *dispatch day*. Refer to "Market Manual 9.3: Operation of the Day-Ahead Commitment Process, Part 4.1.1: Initial Hours of Operation" for more information on how the IHO is determined.

12. The DA-PCG *settlement amounts* for the calculation of the hours to complete your MGBRT will appear on your *settlement statements* for the second day.

13. We calculate your revenues accrued during the DACP start event. The revenues included in the calculation are:

    - *Energy* revenues up to the *schedule of record*,
    - Congestion Management Settlement Credit (CMSC) for *energy* output up to the *schedule of record*,
    - Net *operating reserve* revenues[4] up the *schedule of record*, and
    - Gains for the portion of the *schedule of record* not implemented in the real-time as a result of economic selection (where the real-time *offer* price is greater than the day-ahead *offer* price).[5,6]

14. We compare the revenues accumulated as described above to the total day-ahead costs. When your total costs exceed your revenues, you will be paid the difference through the DA-PCG *settlement amounts* unless the *IESO* withholds payments due to ramping (refer to section 5.4.1 "DA-PCG Reversal Due to Ramping Limitations" for further details).

15. For the DA-PCG *settlement amounts* for hours scheduled past the midnight boundary to complete your MGBRT, we will take into account that your minimum generation costs[7] are included in your day-ahead costs in the previous day (i.e., your escalating start-up *offers*). We will do this using 'clawback' *settlement amounts*.

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[4] The net *operating reserve* revenue is the *operating reserve* revenue earned plus *operating reserve* congestion management settlement credits (CMSC) less *operating reserve* costs (operating reserve *offers*).

[5] If you are committed to run in the DACP and do not get scheduled for your full day-ahead schedule in real-time, your guarantee payment will be reduced to account for any savings represented by higher real-time *offers* for that portion of *energy* not scheduled in real-time.

[6] See footnote 3.

[7] Minimum generation costs are comprised of speed no load costs plus your *price-quantity pairs* up to MLP.

16. The DA-PCG payment is calculated for each DACP start event individually as sum of the following:

    - We calculate the DA-PCG, excluding the start-up cost, for each interval and sum the results for each hour in the DACP start event.

    - We calculate the start-up cost for each DACP start event and apply it to the first hour in the DACP start event.

17. The *IESO-administered markets* will be balanced with an uplift charge for the cost of the PCGs shared by loads and exporters (*charge type* 1550 Day-Ahead Production Cost Guarantee).

5.2 How the DA-PCG is Settled for Pseudo Units

We *settle* the Day-Ahead Production Cost Guarantee (DA-PCG) for the physical resources associated to a *pseudo unit* (*PSU*) in a manner similar to the way we *settle* for resources not associated with a *PSU*. The following exceptions apply:

- For your steam turbine (ST) to be eligible to receive the DA-PCG, we determine (for each continuous block of hours where the ST received a day-ahead schedule) if at least one of its associated combustion turbines (CTs) that contributed to the continuous day-ahead schedule of the ST, had its breakers closed by the start of the first interval of the first DACP scheduled hour of that associated CT start,[8]

- For your CT associated to a *PSU*, the CT IHO = PSU IHO, and

- For your ST associated to *PSU*s scheduled over midnight, the Variant for the DA-PCG calculation is determined as follows:

    - For each *PSU* associated to the ST, we calculate the number of hours the ST is scheduled over midnight to complete MGBRT ($b_{\text{for each PSU}}$) as:

      $b_{\text{for each PSU}} = \text{maximum}[(\text{MGBRT} - \text{IHO}), 0] \times (1 - a)$.

  Where:

    - a = 1 if the *PSU* is operating in single cycle mode, or

    - a= 0 if the *PSU* is not operating in single cycle mode.

  We determine the number of hours the ST is scheduled over midnight by taking the maximum of the results calculated for each *PSU* ($b_{\text{for each PSU}}$):

    - If the result is greater than zero, then the DACP start event is a Variant 2 for those hours, or

    - If the result is equal to zero, then the DACP start event is a Variant 3.

[8] For *settlement* purposes, the breaker close for the CT is identified by using *revenue meter* data. A CT is considered to have closed its breaker when *revenue meter* data indicate a value greater than zero that is sustained for four consecutive intervals.

For the *day-ahead costs* we:

- Reconstruct the day-ahead *energy offer* for the *PSU* into separate Derived Interval Price Curves (DIPC) for each of the CTs and for the ST, (See ‘Appendix B: DIPC Formulation’ for a detailed description of how we calculate DIPC),
- Divide the day-ahead *PSU* speed no load and start-up costs between the CT and ST resources according to the ST Portion of the MLP Operating Region, and
- Determine the guaranteed portion of the day-ahead ST *energy* schedule eligible for a DA-PCG (Derived Interval Guarantee Quantity [DIGQ]). See ‘Appendix C: DIGQ Formulation’ for a detailed description of how we calculate DIGQ.
- The DA-PCG Clawback *settlement amounts* will use the *minimum loading point* used as the day-ahead PCG constraint as calculated and stored for each physical resource as described in “Market Manual 9.4: Real-Time Integration of the Day-Ahead Commitment Process”, section ‘4.1.2.2: DACP Commitments – PCG Eligible Generators (Combined Cycle Plant)’.
- The start-up cost is calculated for the CTs based on when the CT achieves MLP, as submitted in the Daily Generator Data (DGD).
- The ST portion of the startup cost for each *PSU* is based on when the associated CT achieves MLP. For example:
    - ST DA schedule: HE2 – HE10, *PSU*1 DA schedule: HE2 – HE5, *PSU*2 DA schedule: HE4 – HE10
    - The ST portion of the SUC for *PSU*1 is based on when CT1 achieves MLP in HE2 and the ST portion of the SUC for *PSU*2 is based on when CT2 achieves MLP in HE4. The two ST portions for each of the *PSU* SUCs are summed together to determine the SUC for the ST.

5.3 How DA-PCG Translates to your Settlement Statement

The DACP uses *charge types* from our *settlement* system. We settle the DACP using the *settlement amounts* described in the *market rules*. Your *settlement statements* reflect these *settlement amounts* under their associated *charge types*. For descriptions of the *charge types*, refer to “IESO_LST_0001 IESO Charge Types and Equations” and “IESO_SPEC_0005 File Format Specifications for Settlement Statement Files and Data Files”. Table 5-1 lists the relationships between *charge types* and *settlement amounts*.

Table 5-1: Day-Ahead Production Cost Guarantee Charge Types and Settlement Amounts

Charge Type	Settlement Amount
183 Generation Cost Guarantee Recovery Debit	Recovers cost of the real-time guarantee (Spare Generation Online [SGOL])
1500 Day-Ahead Production Cost Guarantee Payment – Component 1 and Component 1 Clawback	For calculating the difference between *energy* revenue and day-ahead costs for the day-ahead schedule *settlement amount*
1501 Day-Ahead Production Cost Guarantee Payment – Component 2	For calculating costs incurred or revenues earned from the proportion of the day-ahead schedule not implemented in real-time *settlement amount*
1502 Day-Ahead Production Cost Guarantee Payment –Component 3 and Component 3 Clawback	For calculating revenue earned from CMSC for the day-ahead schedule *settlement amount*
1503 Day-Ahead Production Cost Guarantee Payment –Component 4	For calculating net revenue earned from *operating reserve* for the day-ahead schedule *settlement amount*
1504 Day-Ahead Production Cost Guarantee Payment –Component 5	For calculating as-offered day-ahead costs for start-up *settlement amount*
1505 Day-Ahead Production Cost Guarantee Payment Reversal	For calculating the reversal DA-PCG *settlement amount* when the total of *charge types* 1500 through 1504 is a less than zero (i.e. a charge to the *market participant*)
1550 Day-Ahead Production Cost Guarantee Debit	Recovers cost of the day-ahead production cost guarantees

5.4 Special Exceptions

5.4.1 Day-Ahead Production Cost Guarantee Reversal Due to Ramping Limitations

When a *generation unit* receives *a schedule of record* in HE 1 of Day 0 for the purpose of ramping down to an offline status, it may receive a Variant 3 type Day-Ahead Production Cost Guarantee (DA-PCG) payment. These payments are attributed to the Day-Ahead calculation engine (DACE) committing the unit in order to respect the technical ramping limitation of the *generation unit*. According to Chapter 9, section 4.7D.7 of the *market rules*, the *IESO* may withhold or recover such payments made in respect of the *generation unit* if the following conditions exist:

1. The *generation unit* is online in Day 1, HE24 in any *pre-dispatch schedule* other than a *schedule of record*; and
2. The *generation unit* receives a Variant 3 type *schedule of record* in order to ramp down the *generation unit* to an offline status; and
3. The *generation unit* would not have otherwise been economic in Day 0, HE1.

If all three conditions are met, the *IESO* will apply a month-end manual adjustment against all DA-PCG payments for the Variant 3 DACP start event on the *preliminary* and *final settlement statement* on the last *trading day* of the month.

– End of Section –

6. Day-Ahead Fuel Cost Compensation due to De-commitment

In addition to the DA-PCG, the DACP ensures you are compensated for any fuel costs incurred for a de-commitment event. For *reliability* reasons, we may de-commit a *generator* before the day-ahead committed schedule has been completed in real-time. When this occurs, you may submit a fuel cost compensation (FCC) claim for the costs incurred securing any unused fuel day-ahead. Compensation claims are allowable up to the *minimum loading point* for the hours which had been scheduled and committed day-ahead and decommitted in real-time. Submit “IESO-FORM-1654 Fuel Cost Compensation” no later than one month after the *trading day* appeared on your *invoice*. When we have validated the claim, you will be compensated for the cost of unused fuel represented by c*harge type* ‘1138 Day-Ahead Fuel Cost Compensation Credit’.

Any day-ahead fuel cost payments will be recovered through an uplift charged to loads, including exports, reflected in *charge type* ‘1188 Day-Ahead Fuel Cost Compensation Debit’.

6.1 How DA-FCCs Translate to your Settlement Statement

Table 6-1 lists the *charge types* involved in the FCC process. For a full description of *charge types*, refer to “IESO_LST_0001 IESO Charge Types and Equations” and “IESO_SPEC_0005 File Format Specifications for Settlement Statement Files and Data Files”.

Table 6-1: Day-Ahead Fuel Cost Compensation Charge Types and Settlement Amounts

Charge Type	Settlement Amount
1138 Day-Ahead Fuel Cost Compensation Credit	For calculating DA-FCC *settlement amount*
1188 Day-Ahead Fuel Cost Compensation Debit	Monthly uplift *charge type* Recovers cost of *charge type* 1138 Day-Ahead Fuel Cost Compensation Credit

– End of Section –

7. Day-Ahead Generator Withdrawal Charge

The DACP strives to ensure that DA-PCG eligible *generation units* perform in real-time as committed in the day-ahead *schedule of record*. If you withdraw from your day-ahead commitment in real-time and the withdrawal is within your control[9], you will be subject to the day-ahead *generator* withdrawal charge (DA-GWC). The purpose of this charge is to:

- Reinforce the *reliability* benefit of day-ahead commitments,
- Require *generators* to share in the risk of an upward price movement between day-ahead and real-time if they fail to deliver, and
- Allocate the proceeds from the charge to loads and exports that are exposed to these price movements.

7.1 How DA-GWCs are Settled

1. We will assess the Day-Ahead Generator Withdrawal Charge for each DACP start event individually.

2. We apply withdrawal charges to day-ahead scheduled *generators* under the following circumstances:
   - Your *generation unit* is included in the *schedule of record*, thus obtaining financial risk protection through the DA-PCG, and
   - You withdraw your commitment from the *real-time market* by withdrawing your *offers*.

3. The withdrawal charge *settlement amount* is a function of:
   - The difference in price between the day-ahead energy *offer* submitted to the day-ahead commitment process and the Ontario *energy price* determined from the unconstrained run of the *real-time market*, and
   - The *minimum loading point* quantity as used in the DACP to schedule the quantity in the day-ahead *schedule of record*.

4. The Ontario *energy price* used in the calculation of the DA-GWC is dependent on the time the withdrawal notification was received by the *IESO*:
   - If withdrawal notification is received at or before four hours prior to the first withdrawal hour in real time (PD-4), then the minimum of the hour ahead Pre-dispatch Ontario market clearing price and the *real-time market* clearing price is used.
   - If withdrawal notification is received later than PD-4, then the *real-time market* clearing price is used.

[9] A withdrawal within your control is identified by the removal of your *offers* from the *real-time market* accompanied by the 'withdrawal' reason code.

5. If you do not notify us of your intent to withdraw, and you do not inject for your entire day-ahead scheduled period, then the Ontario *energy price* used in the calculation of the DA-GWC is the *real-time market* clearing price.

6. If you withdraw your *offers* in *real-time* for DACP start events that are scheduled over midnight to complete your *minimum generation block run-time*, you will be assessed the DA-GWC for the hours withdrawn in the first day independent of the hours withdrawn in the second day. We will treat these as two individual DACP start events for the purposes of assessing the DA-GWC.

7. The *settlement amount* for the assessment of the hours to complete your *minimum generation block run-time* (MGBRT) will appear on your *settlement statements* for the second day.

8. We will calculate the DA-GWC charge for each interval for each hour that is withdrawn and sum the results for each DACP start event. We will apply the *settlement amount* to the first hour in the DACP start event.

9. Proceeds from the charge are allocated to loads and exports that are exposed to these price movements through *charge type* '1560 Day-Ahead Generator Withdrawal Rebate'.

7.1.1 How DA-GWCs are Settled for PSUs

We settle the DA-GWC for resources associated to a *pseudo unit* (*PSU*) in a manner similar to the way we settle for resources not associated to a *PSU* with the following exceptions:

- We use the Derived Interval Price Curve in place of the day-ahead *energy offer* curve, and
- We use the *minimum loading point* (MLP) that is equal to the constraints applied to the resource. The applied constraints are based on the Daily Generator Data MLP as described in the "Market Manual 9.4: Real-Time Integration of the Day-Ahead Commitment Process", section '4.1.2.2: DACP Commitments – PCG Eligible Generators (Combined Cycle Plant)'.

7.2 How DA-GWCs Translate to your Settlement Statement

Table 7-1 lists the *charge types* involved in the *generator* withdrawal charge process. For a full description of new and modified *charge types*, refer to "IESO_LST_0001 IESO Charge Types and Equations" and "IESO_SPEC_0005 File Format Specifications for Settlement Statement Files and Data Files".

Table 7-1: Day-Ahead Generator Withdrawal Charge Types and Settlement Amounts

Charge Type	Settlement Amount
1510 Day-Ahead Generator Withdrawal Charge	For calculating Day-Ahead Generator Withdrawal Charge *settlement amount*
1560 Day-Ahead Generator Withdrawal Rebate	Daily uplift *charge type* Recovers cost of *charge type* 1510 Day-Ahead Generator Withdrawal Charge

– End of Section –

8. Intertie Offer Guarantee

The Intertie Offer Guarantee (IOG) payment process was added to the day-ahead commitment process (DACP) to allow *market participants* to be paid a single IOG payment for an import transaction, net of any offset. Import transactions that are part of linked wheels are not eligible for an IOG payment.

If your underlying import is part of an implied wheel-through transaction, it is subject to the IOG Offset process. The IOG Offset process claws back IOG payments to import transactions associated with "implied wheel" positions where no net power is provided to the Ontario marketplace.

The day-ahead *intertie offer* guarantee (DA-IOG) and real-time *intertie offer* guarantee (RT-IOG) are calculated as per "IESO Charge Types and Equations"; however they are not *settled* separately. The results of the DA-IOG and RT-IOG processes are fed into the IOG Offset process where we determine the IOG offsets and the resulting net IOG payment. The calculated DA-IOG payments, the calculated RT-IOG payments, and their associated import megawatts (MWs) are passed to the IOG *settlement* process, as identified in section '8.4 How IOG is Settled'.

8.1 DA-IOG Description

The DA-IOG provides an incentive for *market participants* to participate in DACP by ensuring an import scheduled day-ahead will at least realize its day-ahead "as-offered" costs when it flows in real-time.

Import *offers* into the DACP are voluntary. You may also offer *imports* into the *real-time market*. If you are participating in the day-ahead, your real-time *offers* may be in addition to or may replace your day-ahead import transactions.

Bids to export from Ontario are voluntary and are considered in the DACP; however there is no equivalent guarantee for exports.

8.2 How DA-IOG is Settled

Like the RT- IOG, the DA-IOG is based on an assessment of the implied level of operating profit on the day-ahead import transaction. If the implied operating profit for the import transaction for the hour is a net loss, then you are compensated for that net loss.

The DA-IOG is based on the lesser of the day-ahead and real-time constrained quantities. As such, the guarantee covers import transactions up to the quantity that flows in real-time. The process is as follows:

1. To receive the DA-IOG:
    - You must be included in the *schedule of record*,
    - Your import must not be part of a day-ahead linked wheel or be converted to a linked wheel in the *real-time market*, and

- The import must be delivered into the *real-time market*[10] and must meet the following conditions:
    - The same *market participant* must conduct the import transaction in real-time as was scheduled for the same hour in the s*chedule of record*, and
    - The transaction must be scheduled in real-time at the same MSP[11] and CSP[12] as used to schedule the import in the DACP. The combination of an MSP and CSP denotes the unique location of an *intertie* transaction for *settlement* purposes. Coupled with the *market participant* identity, the *intertie* transaction is made unique from all other *intertie* transactions in the same *settlement hour*.

2. We will calculate a DA-IOG payment for each interval and sum the results for each hour for all import transactions scheduled in the DACP (as reflected in the *schedule of record*) and delivered into the *real-time market*.

3. The total day-ahead costs will be calculated by the *IESO* and will be the sum of the following costs:
    - Incremental *energy*: *energy offers* for the *schedule of record*, and
    - Cost of arranging the delivery for the portion of the *schedule of record* not implemented in the real-time as a result of economic selection (where the real-time *offer* price is less than the day-ahead *offer* price).[13]

4. We calculate your revenues accrued during the hour. The revenues included in the calculation are:
    - *Energy* revenues up to the *schedule of record*,
    - Congestion Management Settlement Credit (CMSC) for *energy* output up to the *schedule of record*, and
    - Gains for the portion of the *schedule of record* not implemented in real-time as a result of economic selection (where the real-time *offer* price is greater than the day-ahead *offer* price).[14]

5. We compare the revenues accumulated as described above to the total day-ahead costs. When your total costs exceed your revenues, the difference is stored as the calculated DA-IOG amount and is fed to the IOG process.

[10] Delivery in real-time' means that you successfully schedule (i.e., you receive a constrained schedule in the hour-ahead pre-dispatch) and flow an import transaction in real-time (i.e., you deliver a quantity of *energy* in real-time equal to that schedule). You must be scheduled in real-time during the hour corresponding to the hour your import was scheduled in the *Schedule of Record*, and at the same location where your day-ahead import was originally scheduled (i.e., at the same market scheduling point [MSP] and constrained scheduling point [CSP]).

[11] Market Scheduling Point (MSP) is equivalent to *intertie zone* as defined in the *market rules*.

[12] Constrained Scheduling Point (CSP) is equivalent to *boundary entity* defined by the *market rules*.

[13] If you are committed to run in the DACP and do not get scheduled for your full day-ahead schedule in real-time, your guarantee payment will be increased to account for any costs represented by lower real-time *offers* for that portion of *energy* not scheduled in real-time.

[14] If you are committed to run in the DACP and do not get scheduled for your full day-ahead schedule in real-time, your guarantee payment will be reduced to account for any savings represented by higher real-time *offers* for that portion of *energy* not scheduled in real-time.

8.3 IOG Offset

The Intertie Offer Guarantees (IOGs) are subject to IOG offsets if the underlying import is part of an implied wheel-through transaction, either in day-ahead, real-time, or both. The IOG process *settlement* reverses IOG payments to import transactions associated with "implied wheel-through" positions where no net power is provided to the Ontario marketplace.

8.4 How IOG is Settled

The *IESO*:

1. Calculates the DA-IOG rate ($/MW) for each import transaction.

2. Stacks imports, for a *market participant*, for an hour, by MWs (whole transactions) in order of increasing DA-IOG rate ($/MW) per transaction.

3. Determines the total day-ahead export MW, by summing the day-ahead exports MWs for each export transaction for a *market participant*, for an hour.

4. Claws back the day-ahead import schedule up to the level of the total day-ahead export MW starting with the import transaction with the lowest DA-IOG rate.

5. Determines a DA-IOG Offset flag for each day-ahead import transaction receiving DA-IOG dollars ($), by evaluating the export MW quantity being clawed back as follows:
   - If the export MW quantity being offset is greater than 50% of the day-ahead import MW quantity, then the DA Offset Flag is set to "Y" as the transaction is considered to be part of an implied linked wheel.
   - For a day-ahead transaction that was not offset by day-ahead export MW, the DA Offset Flag is set to "N".

6. Assesses and splits the real-time import transactions with calculated DA-IOG payments and calculated RT-IOG payments, and – for those whose day-ahead import MW increases in the real time – calculates as follows:
   - The real-time constrained import MW quantity for the first of the two transactions is the import originally scheduled day-ahead. The (revised) calculated RT-IOG payment for this transaction is equal to the calculated DA-IOG payment from the original day-ahead transaction.
   - The real-time constrained import MW quantity for the second transaction is the incremental constrained import MW quantity scheduled in real-time above the day-ahead import MW quantity. The (revised) calculated RT-IOG payment for this transaction is the maximum of zero or the calculated RT-IOG payment minus the calculated DA-IOG payment.

7. Determines the (revised) RT-IOG rate ($/MW) for the split transactions using the revised real-time constrained import schedule for the split transactions.

8. Determines the IOG Settlement Rate ($/MW) for each import transaction receiving a calculated RT-IOG payment, and/or receiving a calculated DA-IOG payment. The IOG Settlement Rate is determined based on whether or not a transaction is offset day-ahead as follows:

- If the DA-IOG Offset flag is 'Y', set the IOG Settlement Rate ($/MW) equal to the RT-IOG rate.
- If the DA-IOG Offset flag is 'N', set the IOG Settlement Rate ($/MW) equal to the maximum of the DA-IOG rate or the RT-IOG rate.

Note: If, for an import transaction, a calculated DA-IOG ($) payment exists, but no RT-IOG ($) exists, then the Settlement rate ($/MW) is set to the DA-IOG rate ($/MW) as the RT-IOG rate ($/MW) would be evaluated as zero.

9. Determines a gross IOG payment for each import transaction as either the calculated DA-IOG payment, the calculated RT-IOG payment, or the revised calculated RT-IOG payment associated with the IOG Settlement rate (i.e., RT-IOG rate or MAX[DA-IOG rate, RT-IOG rate]).

   Note: The Gross IOG payment is the IOG payment before any IOG offset in the real-time is taken into account.

10. Removes import transactions with IOG Settlement rate of $0/MW from the stack for IOG offset and payment process.

11. Stacks the import transactions for a *market participant*, for the hour by the IOG Settlement Rate determined in step 7, in the order of increasing IOG Settlement Rate.

12. Determines the total real-time export MW by summing the day-ahead exports MWs for each export transaction for a *market participant* for an hour.

13. Claws back the real-time constrained import schedule up to the level of the total real-time export MW starting with the import transaction with the lowest IOG Settlement rate.

14. Determines the IOG Offset amount for each import transaction by multiplying the IOG Settlement Rate by the real-time Offset export MW.

15. Determines the net IOG *settlement amount* for each transaction for a *market participant* for an hour, by subtracting the IOG Offset amount from the gross IOG dollar amount determined in step 12.

    Note: On the *settlement statements*, related split transactions are re-combined resulting in a single IOG payment for an import transaction for a *market participant*.

16. Distributes the net IOG *settlement amount* for each import transaction through charge type 1131, where the net IOG *settlement amount* is greater than zero.

17. The *IESO-administered* markets will be balanced with an uplift charged to loads, including exports, reflected in Net Energy Market Settlement Uplift (*charge type* 150) for the cost of the IOGs.

8.5 How IOG Translates to your Settlement Statement

Table 8-1 lists the *charge types* involved in the Intertie Offer Guarantee compensation process. For a full description of the *charge types*, refer to "IESO_LST_0001 IESO Charge Types and Equations" and "IESO_SPEC_0005 File Format Specifications for Settlement Statement Files and Data Files".

Table 8-1: Intertie Offer Guarantee Charge Types and Settlement Amounts

Charge Type	Settlement Amount
150 Net Energy Market Settlement Credit (NEMSC) component of hourly uplift	Balances *charge type* 1131 (also includes *charge types* 100,101,103 and 104)
1131 Intertie Offer Guarantee	For calculating IOG *settlement amount*

– End of Section –

9. Intertie Failure Charges

The day-ahead commitment process (DACP) strives to ensure that *intertie* transactions scheduled for Ontario actually flow in real-time. If your day-ahead transaction fails to flow in whole or in part in real-time, there may be automatic day-ahead failure charges applied to you through the *settlement process*.

The purpose of these charges for non-linked wheels is to:

- Reinforce the *reliability* benefit of day-ahead import transactions,
- Require importers and exporters to share the risk of an upward price movement between day-ahead and real-time if they fail to deliver, and
- Allocate the proceeds from the charge to loads and exports that are exposed to these price movements.

The purpose of these charges for linked wheels is to:

- Reinforce the *reliability* benefit of day-ahead transactions,
- Require importers and exporters to share in the risk of congestion that limited the scheduling of other day-ahead transactions, and
- Allocate the proceeds from the charge to loads and exports that are exposed to these congestion costs.

The day-ahead failure charges are closely related to the real-time *intertie* transaction failure charges. These charges may be applied to imports and exports that are scheduled in the hour-ahead *pre-dispatch schedule* but fail to flow in real-time. S ome details of the real-time transaction *intertie* failure charges are described in this *market manual*. Refer to "Market Manual 5: Settlements, Part 5.5: Physical Markets Settlement Statements" for more information on the real-time import and export failure charges.

9.1 Intertie Transaction Reason Codes and Resulting Settlement Treatment

We may apply a 'reason code' when we manually alter an import or export schedule. The reason codes are defined in Table 3-5 of the *IESO* Technical Interface document "Format Specifications for Settlement Statement Files and Data Files" (IMP_SPEC_0005). Refer to "Market Manual 4: Market Operations, Part 4.3: Real-time Scheduling of the Physical Markets" for more information about applying reason codes to import and export schedules.

Table 9-1 contains the reason codes and the resulting treatment of Congestion Management Settlement Credit (CMSC) and the day-ahead and real-time failure charges.

For transaction failure charges:

- "Yes" indicates that the criteria of a legitimate reason for failure as described in the *market rules* has been met, and the transaction is exempt from failure charges.
- "No" indicates that the criteria of a legitimate reason for failure as described in the *market rules* has not been met, thus exposing the transaction to failure charges.

Table 9-1: Intertie Reason Codes and Treatment of CMSC and Intertie Failure Charges

Code Entered	DSO[15] Treatment	CMSC Treatment	DA IFC Exempt (Import)	DA EFC Exempt (Export)	DA LWFC Exempt	RT IFC Exempt (Import)	RT EFC Exempt (Export)	DA-IOG Component #2
OTH	Constrained Schedule equal to Market Schedule	No	No	No	No	No	No	No
TLRe	Constrained Schedule equal to Market Schedule	No	Yes	Yes	Yes	Yes	Yes	No
TLRi	Constrained Schedule not necessarily equal to Market Schedule	Yes or No based on DSO schedules	Yes	Yes	N/A	Yes	Yes	Yes
ORA	Constrained Schedule not necessarily equal to Market Schedule	Yes or No based on DSO schedules	Yes or No based on RT Offer Price Test (1)	Yes or No based on RT Offer Price Test(1)	N/A	N/A	Yes	Yes
MrNh	Constrained Schedule equal to Market Schedule	No	No	No	N/A	Yes	Yes	No
ADQH	Constrained Schedule equal to Market Schedule	No	Yes or No based on RT Offer Price Test(1)	Yes or No based on RT Offer Price Test (1)	N/A	Yes	Yes	Yes
NY90	Constrained Schedule not necessarily equal to Market Schedule	Yes or No based on DSO schedule	Yes or No based on RT Offer Price Test (1)	Yes or No based on RT Offer Price Test (1)	N/A	N/A	N/A	Yes
AUTO	Constrained Schedule not necessarily equal to Market Schedule	Yes or No based on DSO schedule	Yes or No based on RT Offer Price Test (1)	Yes or No based on RT Offer Price Test (1)	Yes or No based on RT Offer Price Test (1)	N/A	N/A	Yes

(1) RT Offer Price Test: IF DA Import Scheduled quantity is offered in RT at –MMCP then DA-IFC, DA-EFC is exempt.

9.2 Day-Ahead Import Failure Charge

The day-ahead import failure charge (DA-IFC) is applied as follows:

The *IESO*:

- Determines the quantity of the import transaction shortfall (if any),
- Determines if the transaction is exempt from the charge as result of a legitimate reason (as per the *intertie* reason codes listed in Table 9-1), meeting the meaning of Chapter 7, Section 7.5.8B of the *IESO* "Market Rules", for failing to flow in real-time, and

[15] DSO = Dispatch Scheduling and Optimization

- If the transaction is not exempt from the charge, we calculate the difference between the transaction *offer* price and the hour ahead Pre-dispatch *energy* price (the implied operating profit) multiplied by the quantity of the import failure. This amount reflects the impact to the market of the import failure.

9.2.1 How DA-IFCs are Settled

We apply failure charges to day-ahead imports under the following circumstances:

- Your import is included in the *schedule of record*, thus obtaining financial risk protection through the DA-IOG and
- Your import was not scheduled in the hour ahead Pre-dispatch[16].

The import failure *settlement amount* is the minimum of:

- The difference in price between the submitted day-ahead *energy offers* and the hour ahead Pre-dispatch Ontario *energy price*, for the change from the day-ahead import transaction quantity to the hour ahead Pre-dispatch import transaction quantity,
- The maximum of zero, or the hour ahead Pre-dispatch *offer* to increase the quantity scheduled in the hour ahead Pre-dispatch to the quantity scheduled day-ahead, less the day-ahead *offer* to increase the quantity scheduled in the hour ahead Pre-dispatch to the quantity scheduled day-ahead[17], or
- The day-ahead import scheduling deviation quantity times the maximum of zero or the hour ahead Pre-dispatch *energy market price* in the Ontario zone.

Your import transaction may be exempted from these failure charges if we determine, or you demonstrate that the failure of the day-ahead import transaction to be scheduled in Pre-dispatch is caused by legitimate reasons. Generally, these reasons for import failure are beyond your control or due to errors or actions by the *IESO* or an external system operator[18]. We may determine these reasons or you can submit them to us for assessment through the *notice of disagreement* (NOD) process. Refer to “Market Manual 5: Settlements, Part 5.5: Physical Markets Settlement Statements”, Section 1.5, Submitting a Notice of Disagreement.

Proceeds from the charge are allocated to loads and exports exposed to these price movements through *charge type* ‘186 Intertie Failure Charge Rebate’.

[16] A day-ahead import is considered to have delivered into the *real-time market* if:

- The same *market participant* that had the import scheduled in the *schedule of record* conducts the real-time import,
- The import quantity scheduled in the real-time constrained schedule is the same as the *schedule of record* constrained schedule, and
- The MSP and CSP used for the day-ahead import are the same as those used for the real-time import. The specific combination of a MSP and CSP is the unique location of an *intertie* transaction for *settlement* purposes. Coupled with the identity of the *market participant*, the *intertie* transaction itself is unique from all other *intertie* transactions in the same *settlement hour*.

[17] This term will not be calculated when the *market participant* does not offer in pre-dispatch to their full day–ahead scheduled quantity (i.e., within the market participant’s control). The result is that the second component of the failure charge (i.e., the first cap) ceases to be applicable.

[18] Legitimate reasons for failure include ISO *curtailments*, *intertie* limit reduction, and failure to acquire ramping capacity (*IESO* and NYISO).

9.2.2 Real-Time Offer Price Test

The Real-time Offer Price test exempts from the DA-IFC those day-ahead import transactions where the trader has made a best effort to ensure that the import is scheduled in Pre-dispatch. This test is described in "IESO Charge Types and Equations", section 2.6 (IMP_LST_0001), and has the following general characteristics:

- The test seeks to demonstrate a best efforts attempt to schedule a day-ahead import transaction through a real-time *offer* at negative *maximum market clearing price* (–*MMCP*) for a quantity at least equal to the day-ahead import quantity. Demonstration of this best effort allows for exemption from the DA-IFC, even if our Dispatch Scheduling and Optimization (DSO) tool does not produce the required constrained schedule.
- The Real-time Offer Price Test applies in situations where the import transaction is associated with any *intertie metering point*, and has reason code **ORA**, **AUTO**, **NY90**, or **ADQh**. The Real-time Offer Price Test consists of two parts:
  - Part 1: If the real-time import schedule is less than the day-ahead import schedule from the *schedule of record*, then the test will proceed with Part 2. Otherwise, the test ends.
  - Part 2: The first lamination (i.e., the first segment of the *offer* as defined by the first 2 *price-quantity pairs*) of the real-time *offer* must be large enough to cover the entire quantity of the day-ahead import schedule from the *schedule of record*. The first lamination must be offered at negative *maximum market clearing price (–MMCP)*.

  If these two conditions occur, the import transaction is exempt from the DA-IFC. If *eithe*r or both conditions are not met, the import failure is subject to the DA-IFC calculation.

9.3 Day-Ahead Export Failure Charge

The day-ahead export failure charge (DA-EFC) is applied as follows:

The *IESO*:

- Determines the quantity of the export transaction shortfall (if any),
- Determines if the transaction is exempt from the charge as result of a legitimate reason meeting the meaning of Chapter 7, Section 7.5.8B of the *IESO* "Market Rules", for failing to flow in real-time, and
- If the transaction is not exempt from the charge, we calculate the difference between the transaction *bid* price and the hour ahead Pre-dispatch *energy* price (the implied operating profit) multiplied by the quantity of the export failure. This amount reflects the impact to the market of the export failure.

9.3.1 How DA-EFCs are Settled

We apply failure charges to day-ahead exports under the following circumstances:

- Your export is scheduled in the *schedule of record*, and
- Your export was not scheduled in the hour ahead Pre-dispatch[19].

The export failure *settlement amount* is the minimum of:

- The maximum of zero, or the difference in price between the submitted day-ahead *energy bid* and the hour ahead Pre-dispatch Ontario *energy price* for the megawatts (MWs) scheduled day-ahead, but failed to get scheduled in the hour ahead Pre-dispatch,
- The maximum of zero or the day-ahead *bid* to increase the quantity scheduled in the hour ahead Pre-dispatch to the quantity scheduled day-ahead, less the hour ahead Pre-dispatch *bid* to increase quantity scheduled in the hour ahead Pre-dispatch to the quantity scheduled day-ahead[20], or
- The maximum of zero, or the day-ahead *bid* to increase the quantity scheduled in the hour ahead Pre-dispatch to the quantity scheduled day-ahead.

Your export transaction may be exempted from these failure charges if we determine, or you demonstrate that the failure of the day-ahead export transaction to be scheduled in Pre-dispatch is caused by legitimate reasons. Generally, these reasons for import failure are beyond your control, or due to errors or actions by the *IESO* or an external system operator[21]. We may determine these reasons, or you can submit them to us for assessment through the *Notice of Disagreement (NOD)* process. Refer to "Market Manual 5: Settlements, Part 5.5: Physical Markets Settlement Statements", section '1.5 Submitting a Notice of Disagreement'.

Proceeds from the charge are allocated to loads and exports exposed to these price movements through *charge type* '186 Intertie Failure Charge Rebate'.

[19] A day-ahead export is considered to have delivered into the *real-time market* if:

- The s*ame market participant* that had the export scheduled in the *schedule of record* conducts the real-time export,
- *The export quan*tity scheduled in the real-time constrained schedule is the same as the *schedule of record* constrained schedule, and
- The MSP and CSP used for the day-ahead export are the same as those used for the real-time export. The specific combination of a MSP and CSP is the unique location of an *intertie* transaction for *settlement* purposes. Coupled with the identity of the *market participant*, the *intertie* transaction itself is unique from all other *intertie* transactions in the same *settlement hour*.

[20] This term will not be calculated when the *market participant* does not bid in pre-dispatch to their full day–ahead scheduled quantity (i.e. within the *market participant's* control). The result is that the second component of the failure charge (i.e. the first cap) ceases to be applicable.

[21] Legitimate reasons for failure include ISO *curtailments*, *intertie* limit reduction and failure to acquire ramping capacity (*IESO* and NYISO).

9.3.2 Real-Time Bid Price Test

The Real-time Bid Price Test exempts from the DA-EFC those day-ahead export transactions where the trader has made a best effort to ensure that the export is scheduled in Pre-dispatch. This test is described in “IMP_LST_0001 IESO Charge Types and Equations”, section 2.6, and has the following general characteristics:

- The test seeks to demonstrate a best efforts attempt to schedule a day-ahead export transaction through a Pre-dispatch *offer* at positive *maximum market clearing price* (+*MMCP*) for a quantity, at least equal to the day-ahead export quantity. Demonstration of this best effort allows for exemption from the DA-EFC, even if our DSO tool does not produce the required constrained schedule.
- The Real-Time Bid Price Test applies in situations where the export transaction is associated with any *intertie metering point* and has reason code **ORA**, **AUTO**, **NY90**, or **ADQh**.
- The Real-Time Offer Bid Test consists of two parts:
    - Part 1: If the real-time export schedule is less than the day-ahead import schedule from the *schedule of record*, then the test will proceed with Part 2. Otherwise, the test ends.
    - Part 2: The first lamination (i.e., the first segment of the *bid* as defined by the first two *price-quantity pairs*) of the real-time *bid* must be large enough to cover the entire quantity of the day-ahead export schedule from the *schedule of record*. The first lamination must be offered at +*MMCP*.

  If these two conditions occur, the export transaction is exempt from the DA-EFC. If either or both conditions are not met, the export failure is subject to the DA-EFC calculation.

9.4 Day-Ahead Linked Wheel Failure Charge

The day-ahead linked wheel failure charge (DA-LWFC) is applied as follows:

The *IESO*:

- Determines the quantity of the import transaction shortfall (if any) and the quantity of the export transaction shortfall (if any),
- Determines if the transaction is exempt from the charge as a result of a legitimate reason, meeting the meaning of Chapter 7, Section 7.5.8B of the *IESO* “Market Rules”, for failure to flow in real-time, and
- If the transaction is not exempt from the charge, we calculate the failure charge as the minimum of:
    - The difference between the day-ahead price spread and the Pre-dispatch price spread, multiplied by the greater of the quantity of the import failure or the quantity of the export failure. This amount reflects the cost of congestion at the *interties* of the linked wheel failure.
    - The sum of the real-time failure charge for the import MWh failure between day-ahead and Pre-dispatch and the real-time failure charge for the export MWh failure between day-ahead and Pre-dispatch. This amount ensures that the day-ahead linked wheel failure charge is never greater than what the real-time failure charges were to be, thereby removing any incentive that would delay a linked wheel failure to real-time.

9.4.1 How DA-LWFCs are Settled

We apply failure charges to day-ahead linked wheels under the following circumstances:

- Your linked wheel is included in the *schedule of record*, and
- Your linked wheel was not scheduled in the hour ahead Pre-dispatch[22].

The linked wheel failure *settlement amount* is the minimum of:

- The difference in day-ahead price spread and the Pre-dispatch price spread for the maximum of the import MWh failure and the export MWh failure for the linked wheel (day-ahead linked wheel scheduling deviation), or
- The sum of the Real-Time Import Failure Charge (RT-IFC-DALW) and the Real-Time Export Failure Charge (RT-EFC-DALW) for the MWh failure between day-ahead and Pre-dispatch.

Your linked wheel transaction may be exempted from these failure charges if we determine, or you demonstrate, the failure of the day-ahead linked wheel transaction to be scheduled in Pre-dispatch is caused by legitimate reasons. Generally, these reasons for a linked wheel failure are beyond your control, or due to errors or actions by the *IESO* or an external system operator[23]. We may determine these reasons, or you can submit them to us for assessment through the *notice of disagreement* process. Refer to “Market Manual 5: Settlements, Part 5.5: Physical Markets Settlement Statements”, section ‘1.5 Submitting a Notice of Disagreement’.

Proceeds from the charge are allocated to loads and exports exposed to these congestion costs through *charge type* ‘186 Intertie Failure Charge Rebate’.

9.4.2 Real-Time Bid/Offer Price Test

The Real-Time Bid/Offer Price test exempts from the DA-LWFC the day-ahead linked wheel transactions in which the trader has made a best effort to ensure that the linked wheel is scheduled in Pre-dispatch. This test is described in “IMP_LST_0001 IESO Charge Types and Equations”, section 2.6 and has the following general characteristics:

- The test seeks to demonstrate a best efforts attempt to schedule both the import and export legs of a day-ahead linked wheel (DALW) transaction through both:
    - A Pre-dispatch bid at positive *maximum market clearing price (+MMCP)* for a quantity at least equal to the day-ahead export quantity, and
    - A Pre-dispatch offer at *negative maximum market clearing price (–MMCP)* for a quantity at least equal to the day-ahead import quantity.

  Demonstration of this best effort allows for exemption from the RT-EFC-DALW and RT-IFC-DALW, even if our DSO tool does not produce the required constrained schedules.

[22] A day-ahead export is considered to have delivered into the *real-time market* if:

- The sa*me market participant* that had the export scheduled in the *schedule of record* conducts the real-time export,
- The *export quant*ity scheduled in the real-time constrained schedule is the same as the *schedule of record* constrained schedule, and
- The MSP and CSP used for the day-ahead export are the same as those used for the real-time export. The specific combination of a MSP and CSP is the unique location of an *intertie* transaction for *settlement* purposes. Coupled with the identity of the *market participant*, the *intertie* transaction itself is unique from all other *intertie* transactions in the same *settlement hour*.

[23] Legitimate reasons for failure include ISO *curtailments*, *intertie* limit reduction and failure to acquire ramping capacity (*IESO* and NYISO).

- The Real-Time Bid/Offer Price Test applies in situations where the linked wheel transaction is associated with any *intertie metering point*, and has reason code **AUTO**.
- The Real-Time Offer Price Test consists of two parts:
  - Part 1: If the Pre-dispatch import schedule is less than the day-ahead import schedule from the *schedule of record*, then the test will proceed with Part 2. Otherwise, the test ends.
  - Part 2: The first lamination (i.e., the first segment of the *offer* as defined by the first two *price-quantity pairs*) of the Pre-dispatch *offer* must be large enough to cover the entire quantity of the day-ahead import schedule from the *schedule of record*. The first lamination must be offered at negative *maximum market clearing price (–MMCP)*.

  If these two conditions occur, the *import* portion of the linked wheel transaction is exempt from the DA-IFC-DALW. If either or both conditions are not met, the *import* failure is subject to the RT-IFC-DALW calculation.
- The Real-Time *Bid* Price Test for the export transaction consists of two parts:
  - Part 1: If the Pre-dispatch export schedule is less than the day-ahead export schedule from the *schedule of record*, then the test will proceed with Part 2. Otherwise, the test ends.
  - Part 2: The first lamination (i.e., the first segment of the *bid* as defined by the first two *price-quantity pairs*) of the Pre-dispatch *bid* must be large enough to cover the entire quantity of the day-ahead export schedule from the *schedule of record*. The first lamination must be offered at *+MMCP*.

  If these two conditions occur, the export portion of the linked wheel transaction is exempt from the RT-EFC-DALW. If either or both conditions are not met, the linked wheel failure is subject to the RT-EFC-DALW calculation.

9.5 Intertie Failure Charge Rebate

Proceeds from the charge are allocated to loads and exports exposed to these price movements through *charge type* '186 Intertie Failure Charge Rebate'.

The Intertie Failure Charge Rebate *charge type* (186) allocates the proceeds from the *intertie* failure charges to the *IESO-administered market*. *Charge type* 186 also distributes proceeds from the RT-IFC, the RT-EFC in addition to the DA-IFCs. This component of the *hourly uplift settlement amount* can be transferred as part of a *physical bilateral contract* (see "IESO Charge Types and Equations", section 2.5 for further details).

However, in spite of these *intertie* failure charges, we may take actions to recover amounts where egregious behaviour has occurred. Recoverable *settlement amounts* may include transmission rights payments, congestion management settlement credits, or other *settlement amounts* that were made as a result of that behaviour. Please see section 6.6.10A of Chapter 3 of the "Market Rules" for further details.

9.6 How IFCs, EFCs, and LWFCs Translate to your Settlement Statement

Table 9-2 lists the *charge types* involved in day-ahead and real-time *intertie* failure *charge types*.

For a full description of new and modified *charge types*, refer to "IMP_LST_0001 IESO Charge Types and Equations". For a description of the impact of the DACP *settlement amounts* and the real-time *intertie* failure charges on *preliminary* and *final settlement statements*, refer to "IMP_SPEC_0005 File Format Specification for Settlement Statement Files and Data files". Table 9-2 lists the relationship between failure *charge types* and new *settlement amounts*.

For the DA-LWFC, *charge type* 1134 is allocated to the resource as follows:

- If the import deviation is the larger failure deviation, the charge is allocated to the import resource,
- If the export deviation is the larger failure deviation, the charge is allocated to the export resource, or
- If the import and export failure deviations are the same, the charge is allocated to the import resource.

Table 9-2: Intertie Failure Charge Types and Settlement Amounts

Charge Type	Settlement Amount
135 Real-time Import Failure Charge	For calculating RT-IFC *settlement amount*
136 Real-time Export Failure Charge	For calculating RT-EFC *settlement amount*
1134 Day-Ahead Linked Wheel Failure Charge	For calculating DA-LWFC *settlement amount*
1135 Day-Ahead Import Failure Charge	For calculating DA-IFC *settlement amount*
1136 Day-Ahead Export Failure Charge	For calculating DA-EFC *settlement amount*
186 Intertie Failure Charge Rebate	Distributes all amounts collected under *intertie* failure *charge types* 135, 136, 1134, 1135, and 1136. Transferable between parties to a *physical bilateral contract.*

– End of Section –

Appendix A: PSU and Derates

The day-ahead calculation engine schedules the *pseudo unit* (*PSU*) in the following sequence:

1. Schedules the *PSU* to at least the entire MLP quantity first.
2. Schedules the dispatchable region next.
3. Schedules the duct firing region last.

If the dispatchable region is collapsed due to a CT derate, the available dispatchable capacity will be scheduled before duct firing. If the dispatchable region is unavailable, duct firing will be scheduled right after MLP. Duct firing will be scheduled according to *price quantity* pairs associated with duct firing. The *price quantity* pairs are locked to offered capacity and collapse along with the derating. This could result in duct firing capacity being scheduled when it is not economic because the duct firing capacity has become part of the price lamination for the dispatchable region.

PSU resources are derated through either a derate submission for a physical unit or a limitation due to a transmission constraint of either physical resource.

<u>ST Derate</u>

- *PSU* Derate Sequence: derates the operating regions from the top-down (Duct Firing Range first, Dispatchable Range second, then to total outage).
- The corresponding CT derate per each operating region is equal to:

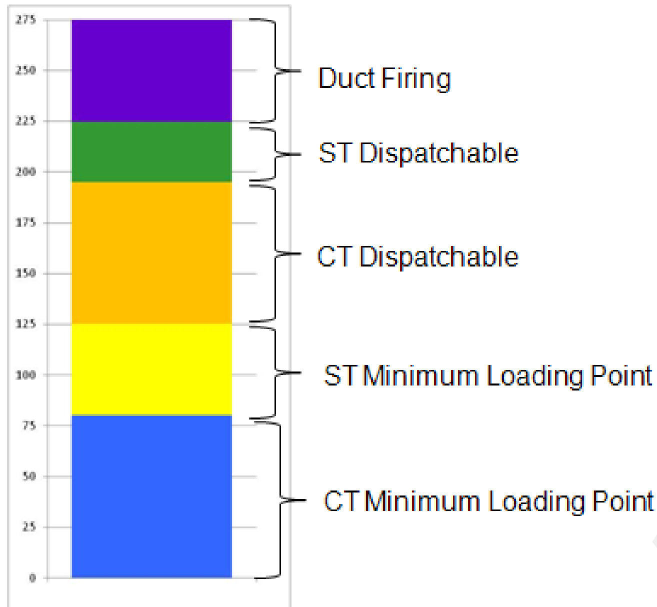
  CT Derate Amt = ST Derate Quantity x OR_ST Share ÷ (1-OR_ST Share)
- *PSU*'s dynamically share available ST capacity. Most economic *PSU* has priority to available ST capacity.

<u>CT Derate</u>

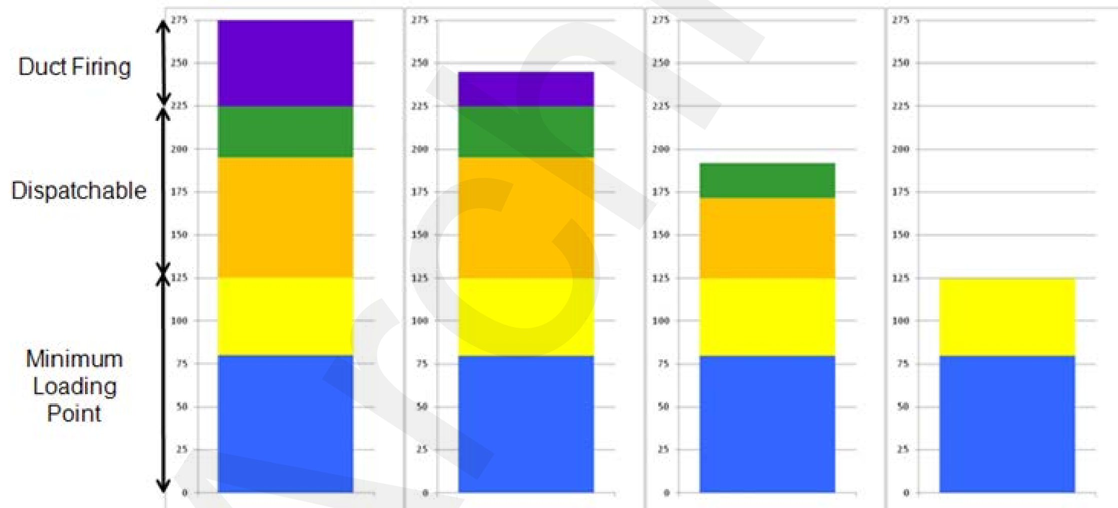
- *PSU* Derate Sequence: derates the operating regions from the middle-out (Dispatchable Range first, then to total outage).
- The corresponding ST derate per each operating region is equal to:

  ST Derate Amt = CT Derate Quantity x (OR_ST Share) ÷ OR_ST Share
- *PSU* derate is directly proportional to derate of associated CT

Sections A.1 and A.2 illustrate a *PSU* derating due to a ST derate and a CT derate. The *PSU* operating regions and legend is presented below.



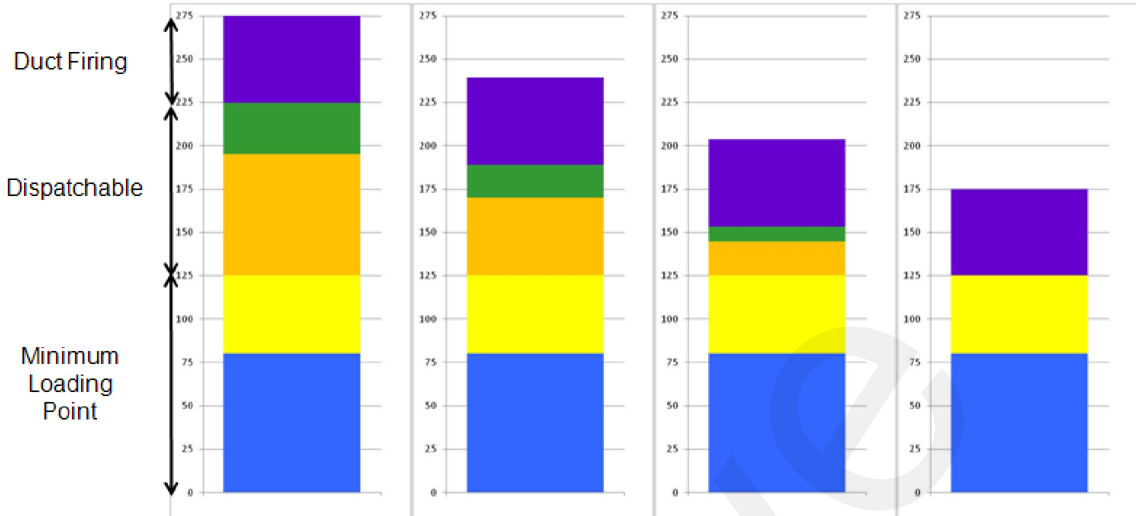
A.1 PSU De-rating due to a ST De-rating



ST De-rate	0MW	30MW	60MW	80MW
PSU De-rate	0MW	30MW	83MW	150MW
CT De-rate*	0MW	0MW	23MW	70MW

* residual derate on the CT

A.2 PSU De-rating due to a CT De-rating



CT De-rate	0MW	25MW	50MW	70MW
PSU De-rate	0MW	36MW	71MW	100MW
ST De-rate*	0MW	11MW	21MW	30MW

* residual derate on the ST

– End of Section –

Appendix B: DIPC Formulation

B.1 PSU Operating Regions

The pseudo unit (*PSU*) model is composed of three operating regions: the MLP region, the dispatchable region and the duct firing region, referred to as the set of regions D = {d1, d2, d3} respectively.

Each operating region has associated parameters that distinguish it from the other regions. For the translation of the three-part day-ahead *PSU offer* curves, the following values are required:

- Operating Region Range Quantity (ORRQ): the maximum capacity of the operating region before any constraints are applied.
- ST Portion: the percent of the *PSU energy* in the operating region that is produced by the ST as calculated by the *IESO* from MP submitted data. Likewise, for the CT, the portion is the percent of the *PSU energy* in the operating region that is produced by the CT, and is calculated as 1 minus the ST Portion.

B.2 General Variables

The general variables are on a *registered facility* basis.

The following variables will apply to the CT delivery points, referred to as the set **CT** = {c1,…,cN} where N is the number of CT units at the combined cycle plant.

Note: The number of CT's at a combined cycle plant is derived and available through registration data.

$AQEI_{k,h}^{c,t}$	=	allocated quantity (in MWh) of *energy* injected by *market participant* 'k' at *CT delivery point* 'c' in *metering interval* 't' of *settlement hour* 'h'[24]

$DA\_DQSI_{k,h}^{c,t}$	=	day-ahead constrained quantity scheduled for injection by *market participant* 'k' at *CT delivery point* 'c' during *metering interval* 't' of *settlement hour* 'h'

$MLP_{k,h}^{c,t}$	=	minimum output of *energy* the *market participant* 'k' at *CT delivery point* 'c' can maintain without ignition support in *metering interval* 't' of *settlement hour* 'h'

The following variable will apply to the ST resource, referred to as *ST delivery point* 's'.

$N_{k,h}^{s,t}$	=	the number of *CT delivery points* registered in *IESO* Registration Solution as associated to *ST delivery point* 's' of *market participant* 'k' in *metering interval* 't' of *settlement hour* 'h'

[24] This is the standard definition in our *Market Rules*, the DA-PCG calculation is only for primary metering points.

B.3 Pseudo Unit Specific Variables

The following variables are on a *pseudo unit* (*PSU*) basis so will apply to the *PSU* delivery points. The *PSU* resources are referred to as the set **PSU** = {p1,…,pN}, where N is the number of CT units.

Note: The *PSU* specific variables are all hourly values and must be applied uniformly to all intervals.

$M_{k,h}^{p,t}$	=	the maximum number of PQ pairs that may be submitted for the day-ahead *energy offers*, equal to [20/$N_{k,h}^{s,t}$] rounded down to the nearest whole number, for *market participant* ‘k’ at *pseudo unit* ‘p’ in *metering interval* ‘t’ of *settlement hour* ‘h’

$DA\_BE_{k,h}^{p,t}$	=	*energy offers* submitted in day-ahead, represented as an $M_{k,h}^{p,t}$ by 2 matrix of *price-quantity pairs* for each *market participant* ‘k’ at *PSU* ‘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

$DA\_DQSI_{k,h}^{p,t}$	=	day-ahead constrained quantity scheduled for injection by *market participant* ‘k’ at *PSU* ‘p’ during *metering interval* ‘t’ of *settlement hour* ‘h’

$ORRQ_{k,h,d}^{p,t}$	=	The DGD calculated *PSU* operating region range quantity for *market participant* ‘k’ at *pseudo unit* ‘p’ in *range* ‘d’ during *metering interval* ‘t’ of *settlement hour* ‘h’

$ST\_Portion_{k,h,d}^{p,t}$	=	The DGD calculated ST Portion, representing the percent of the *PSU* energy that belongs to the ST for *market participant* ‘k’ at *PSU* ‘p’ in *range* ‘d’ during *metering interval* ‘t’ of *settlement hour* ‘h’

B.4 Calculated Variables

For the decomposition of the day-ahead *PSU offers*, the portions of the day-ahead *PSU* schedule in each operating region must be determined. Also, if any CT derate has occurred, the associated *PSU* derated MWs must be removed from the top of the dispatchable region *PSU offers*. This is done through a collapse of the PQ pairs attributed to those MWs, so a fourth region – the collapsed region – must also be determined.

<u>MLP Region Range Quantity (MRRQ)</u>: The day-ahead scheduled quantity in the MLP operating region.

Calculated as,

min(ORRQ for the MLP, Day-ahead PSU schedule)

Defined as:

$MRRQ_{k,h}^{p,t}$	=	quantity of *energy* scheduled in day-ahead in the MLP operating region for *market participant* 'k' at *pseudo unit* 'p' in *metering interval* 't' of *settlement hour* 'h'

$MRRQ_{k,h}^{p,t}$	=	$\mathrm{Min}(ORRQ_{k,h,d1}^{p,t}, DA\_DQSI_{k,h}^{p,t})$

<u>Collapsed Region Range Quantity (CRRQ):</u> The day-ahead scheduled quantity in the MLP and dispatchable operating regions plus any CT derated/collapsed MWs. This is the maximum capacity of the MLP and Dispatchable operating regions before any security constraints or de-ratings are applied.

Calculated as,

$ORRQ\ for\ the\ MLP + ORRQ\ for\ the\ Dispatchable\ Region$

Defined as:

$CRRQ_{k,h}^{p,t}$	=	quantity of *energy* scheduled in day-ahead in the MLP and dispatchable operating regions plus any MWs associated with a CT derate on the *PSU* for *market participant* 'k' at *pseudo unit* 'p' in *metering interval* 't' of *settlement hour* 'h'

$CRRQ_{k,h}^{p,t}$	=	$ORRQ_{k,h,d1}^{p,t} + ORRQ_{k,h,d2}^{p,t}$

<u>Dispatchable Region Range Quantity (DRRQ), (i.e., the day-ahead schedule without duct firing):</u> The day-ahead scheduled quantity in the MLP and dispatchable operating regions. Since the duct firing region is composed of 100% ST *energy*, the DRRQ can be determined using the day-ahead CT schedule and determining the *PSU energy* that would be scheduled for that quantity of CT generation. This value must be greater than the MLP and less than the Collapsed Region Range Quantity.

Calculated as,

If the ST Portion for the Dispatchable Range < 100% **Then**

$$Max\Big(MLP\ Region\ Range\ Quantity,\ Min\Big(Collapsed\ Region\ Range\ Quantity,\ MLP\ Region\ Range\ Quantity + \frac{max(Day\ ahead\ CT\ schedule - CT\ MLP, 0)}{(1 - ST\ Portion\ for\ the\ Dispatchable\ Region)}\Big)\Big)$$

Else

$$Max\big(MLP\ Region\ Range\ Quantity,\ Min(Collapsed\ Region\ Range\ Quantity,\ Day\ ahead\ PSU\ schedule)\big)$$

Defined as:

$DRRQ_{k,h}^{p,t}$	=	quantity of *energy* scheduled in day-ahead in the MLP and dispatchable operating regions for *market participant* 'k' at *PSU* 'p' in *metering interval* 't' of *settlement hour* 'h'

IF $ST\_Portion^{p,t}_{k,h,d2} < 100\%$ **Then**

$DRRQ_{k,h}^{p,t}$	=	$max(MRRQ_{k,h}^{p,t}, min(CRRQ_{k,h}^{p,t}, MRRQ^{p,t}_{k,h} + \frac{max(DA\_DQSI^{c,t}_{k,h} - MLP^{c,t}_{k,h}, 0)}{(1 - ST\_Portion^{p,t}_{k,h,d2})}))$

Else

$DRRQ_{k,h}^{p,t}$	=	$max(MRRQ_{k,h}^{p,t}, min(CRRQ_{k,h}^{p,t}, DA\_DQSI_{k,h}^{p,t}))$

<u>Duct Firing Region Range Quantity (DFRRQ)</u>: The day-ahead scheduled quantity in the MLP, dispatchable and duct firing operating regions plus any CT derated/collapsed MWs.

Calculated as,

Min(ORRQ for the MLP + ORRQ for the Dispatchable Region + ORRQ for the Duct Firing, Max(Day-ahead PSU schedule + Collapsed Region Range Quantity – Dispatchable Region Range Quantity, Collapsed Region Range Quantity))

Defined as:

$DFRRQ_{k,h}^{p,t}$	=	quantity of *energy* scheduled in day-ahead in the MLP, dispatchable and duct firing operating regions plus any MWs associated with a CT derate on the *PSU* for *market participant* 'k' at *PSU* 'p' in *metering interval* 't' of *settlement hour* 'h'

$DFRRQ_{k,h}^{p,t}$	=	$min(ORRQ_{k,h,d1}^{p,t} + ORRQ_{k,h,d2}^{p,t} + ORRQ_{k,h,d3}^{p,t},$ $max(DA\_DQSI_{k,h}^{p,t} + CRRQ_{k,h}^{p,t} - DRRQ_{k,h}^{p,t},$ $CRRQ_{k,h}^{p,t}))$

B.5 Day-ahead Energy Offer Curves

The day-ahead offers are submitted on a *PSU* basis while the real-time *offers* are submitted on a *registered facility* basis. To accurately compare schedules on both offer curves, the day-ahead *energy offers* must be converted onto a *registered facility* basis.

$DIPC_{k,h}^{m,t}$	=	*energy* price curves derived per interval from submitted hourly day-ahead *PSU energy offers*, represented as a N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *delivery point* 'm' (where 'm' is a CT or ST delivery point) during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered price in each *price quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2

For the construction of the derived interval price curves, each PQ pair from the day-ahead *PSU energy offers* will be analyzed so it is correctly split into its CT and ST portions. The quantity value from the PQ pair that is being analyzed will be referred to as DA_BE[i,2], where i is the current row in the PQ Pair matrix.

B.6 Construct the Derived Interval Price Curve for each CT

A derived interval price curve will be constructed for each CT for every interval with a day-ahead schedule as follows:

Using the four calculated region range quantities from section 'B.1 PSU Operating Regions', there are three orderings of the day-ahead *PSU energy offer* quantity ($DA\_BE[i,2]_{k,h}^{p,t}$), and the calculated values that require unique CT quantity calculations. The table below summarizes the three significant orderings and the values that should be calculated.

Table B-1: Calculating CT Quantity based on Ordering of Day-Ahead PSU Energy Offer Quantities and Calculated Upper Limits

Scenario	Ordering	CT Quantity
1	$0 < DA\_BE[i,2]_{k,h}^{p,t} <= MRRQ$	$DA\_BE_{k,h}^{p,t}[i,2]_{k,h}^{p,t} \times (1\text{-}ST\_Portion_{k,h,d1}^{p,t})$
2	$MRRQ < DA\_BE[i,2]_{k,h}^{p,t} <= DRRQ$	$MRRQ_{k,h}^{p,t} \times (1\text{-}ST\_Portion_{k,h,d1}^{p,t}) + (DA\_BE_{k,h}^{p,t}[i,2]_{k,h}^{p,t} - MRRQ_{k,h}^{p,t}) \times (1\text{-}ST\_Portion_{k,h,d2}^{p,t})$
3	$DRRQ < DA\_BE[i,2]_{k,h}^{p,t}$	$MRRQ_{k,h}^{p,t} \times (1\text{-}ST\_Portion_{k,h,d1}^{p,t}) + (DRRQ_{k,h}^{p,t} - MRRQ_{k,h}^{p,t}) \times (1\text{-}ST\_Portion_{k,h,d2}^{p,t})$

For each quantity value in the set of day-ahead *PSU energy offers*, the calculation used to find the corresponding CT quantity will be based on the three scenarios. Scenarios 1 to 3 can be simplified into the one equation, as calculated below:

The derived interval price curve for each CT is calculated as follows:

Derived Interval Price Curve Matrix	=	Price [Row i, Column 1]	Quantity [Row i, Column 2]
$DIPC_{k,h}^{c,t}$	=	$DA\_BE\,[i,1]_{k,h}^{p,t}$	$min(DA\_BE[i,2]_{k,h}^{p,t}, DRRQ_{k,h}^{p,t})$ $-[min(MRRQ_{k,h}^{p,t}, DA\_BE[i,2]_{k,h}^{p,t}) \times ST\_Portion_{k,h,d1}^{p,t}$ $+max(0, min(DRRQ_{k,h}^{p,t}, DA\_BE[i,2]_{k,h}^{p,t}) - MRRQ_{k,h}^{p,t}) \times ST\_Portion_{k,h,d2}^{p,t}]$

Finally any PQ pairs in the CT derived interval price curve that have the same quantity value with the exception of the first instance of that quantity value, will have both the price and quantity components set to zero. This last process is a requirement since the CT DIPC will continue to generate PQ pairs for $DA\_BE[i,2]_{k,h}^{p,t}$ values that exceed the DRRQ. However the calculated quantity will never exceed the DRRQ value, and will be repeated for any $DA\_BE[i,2]_{k,h}^{p,t}$ above that value. This secondary process will ensure that the final CT DIPC maintains a monotonically increasing *offer* curve.

For example given the parameters on the right, and the initial *PSU offer* curve as noted below. The initial CT DIPC calculated based on the formula will generate multiple PQ pairs with a quantity value of 25MW, the secondary process that generates the final CT DIPC will remove all the PQ pairs after the second instance of a duplicated quantity value.

$MRRQ_{k,h}^{p,t}$ =15MW

$DRRQ_{k,h}^{p,t}$ = 50MW

$CRRQ_{k,h}^{p,t}$ = 60MW

$DFRRQ_{k,h}^{p,t}$ = 70MW

$ST\_Portion_{k,h,d1}^{p,t}$ = 50%

$ST\_Portion_{k,h,d2}^{p,t}$ = 50%

Example – illustrated:

Pseudo Unit Offer Curve

Price	Quantity
10	0
10	30
15	40
20	50
25	60
30	70

Initial CT DIPC

Price	Quantity
10	0
10	15
15	20
20	25
25	25
30	25

Final CT DIPC

Price	Quantity
10	0
10	15
15	20
20	25
~~25~~ 0	~~25~~ 0
~~30~~ 0	~~25~~ 0

B.7 Construct the Derived Interval Price Curve for the ST

In constructing the derived interval price curve for the ST, a number of steps are required. These include:

- Constructing a ST Price Curve for each *PSU*
- Determining which *PSU*s are included in the DIPC
- Constructing the DIPC
- Constructing the ST Price Curve for each *PSU*

First, the ST Portion of the *PSU* quantity from each *PSU* PQ pair, referred to as the ST quantity, must be calculated.

$ST\_Q_{k,h}^{p,t}$	=	An M by 1 matrix (where M = $M_{k,h}^{p,t}$, defined in section 'B.3 Pseudo Unit Specific Variables') of *quantity* values calculated from the day-ahead *PSU energy offers* and ST Portions for *market participant* 'k' at *PSU* 'p' during *metering interval* 't' of *settlement hour* 'h'

For each *PSU*, using the four calculated region range quantities from section 'B.1 PSU Operating Regions', there are five orderings of the day-ahead *PSU energy offer* quantity and the calculated values that require unique ST quantity calculations. The table below summarizes the five significant orderings and how the ST quantities will be calculated for each quantity value in the set of day-ahead *PSU energy offers*.

Table B-2: Calculating ST Quantity based on Ordering of Day-ahead PSU Energy Offer Quantities and Calculated Upper Limits

Scenario	Ordering	$ST\_Q_{k,h}^{p,t}$
1	$0 < DA\_BE[i,2]_{k,h}^{p,t} <= MRRQ$	$DA\_BE_{k,h}^{p,t}[i,2]_{k,h}^{p,t} \times ST\_Portion_{k,h,d1}^{p,t}$
2	$MRRQ < DA\_BE[i,2]_{k,h}^{p,t} <= DRRQ$	$MRRQ_{k,h}^{p,t} \times ST\_Portion_{k,h,d1}^{p,t}$ $+(DA\_BE[i,2]_{k,h}^{p,t} - MRRQ_{k,h}^{p,t}) \times ST\_Portion_{k,h,d2}^{p,t}$
3	$DRRQ < DA\_BE[i,2]_{k,h}^{p,t} <= CRRQ$	$MRRQ_{k,h}^{p,t} \times ST\_Portion_{k,h,d1}^{p,t}$ $+(DRRQ_{k,h}^{p,t} - MRRQ_{k,h}^{p,t}) \times ST\_Portion_{k,h,d2}^{p,t}$
4	$CRRQ < DA\_BE[i,2]_{k,h}^{p,t} <= DFRRQ$	$MRRQ_{k,h}^{p,t} \times ST\_Portion_{k,h,d1}^{p,t}$ $+(DRRQ_{k,h}^{p,t} - MRRQ_{k,h}^{p,t}) \times ST\_Portion_{k,h,d2}^{p,t}$ $+ (DA\_BE[i,2]_{k,h}^{p,t} - CRRQ_{k,h}^{p,t}) \times ST\_Portion_{k,h,d3}^{p,t}$
5	$DFRRQ < DA\_BE[i,2]_{k,h}^{p,t}$	$MRRQ_{k,h}^{p,t} \times ST\_Portion_{k,h,d1}^{p,t}$ $+(DRRQ_{k,h}^{p,t} - MRRQ_{k,h}^{p,t}) \times ST\_Portion_{k,h,d2}^{p,t}$ $+ (DFRRQ_{k,h}^{p,t} - CRRQ_{k,h}^{p,t}) \times ST\_Portion_{k,h,d3}^{p,t}$

These five scenarios can be simplified into the following equation:

$ST\_Q_{k,h}^{p,t}$	=	$min(MRRQ_{k,h}^{p,t} , DA\_BE[i,2]_{k,h}^{p,t}) \times ST\_Portion_{k,h,d1}^{p,t}$ $+max(0,min(DRRQ_{k,h}^{p,t}, DA\_BE[i,2]_{k,h}^{p,t})- MRRQ_{k,h}^{p,t}) \times ST\_Portion_{k,h,d2}^{p,t}$ $+ max(0,min(DFRRQ_{k,h}^{p,t}, DA\_BE[i,2]_{k,h}^{p,t}) - CRRQ_{k,h}^{p,t}) \times ST\_Portion_{k,h,d3}^{p,t}$

Once the ST quantities are calculated, they are converted into delta ST quantities for the ST price curve. The ST price curve is constructed of the price from each *PSU* PQ pair and the quantity calculated from the difference between each ST quantity value and the previous. This ST price curve will represent the incremental quantity of *energy* available at each price.

$ST\_PC_{k,h}^{p,t}$	=	An M by 2 matrix (where $M = M_{k,h}^{p,t}$ (defined in section 'B.3 Pseudo Unit Specific Variables')) of *price-quantity pairs* formed from the *price* and the ST Portion of each *quantity* from the submitted in *day-ahead PSU energy offers* for *market participant* 'k' at *pseudo unit* 'p' during *metering interval* 't' of *settlement hour* 'h'

Calculated as:

PQ Pair Matrix	=	Price [Row 'i', Column 1]	Quantity [Row 'i', Column 2]
$ST\_PC_{k,h}^{p,t}$	Row i=1	$DA\_BE[i,1]_{k,h}^{p,t}$	0
	Row i >=2	$DA\_BE[i,1]_{k,h}^{p,t}$	$ST\_Q_{k,h}^{p,t}[i] - ST\_Q_{k,h}^{p,t}[i-1]$

B.8 Determining PSUs included in the DIPC

The set of *PSU offer* curves to be included in the DIPC used for *settlement* calculations must be determined. For each *PSU*, if the ST was withdrawn in real-time or the ST was not withdrawn and the associated CT is injecting ($AQEI_{k,h}^{c,t} > 0$) for the interval then the associated ST price curve will be included in the DIPC used for *settlement*. The table below summarizes the four possible scenarios for the j[th] *PSU*, where j = 1 to $N_{k,h}^{s,t}$ (defined in section 'B.3 Pseudo Unit Specific Variables'), to be assessed for inclusion in the DIPC.

Note: The hourly withdrawal code will apply to all intervals in the hour.

Table B-3: Determining PSUs to be included in DIPC per interval

Scenario			
1	Y	N/A	Y
2	N	Y	Y
3	N	N	N

B.9 Constructing the DIPC

Before constructing the DIPC, the individual ST Price curves of included *PSU*s must be combined into a single ST price curve.

$S\_ST\_PC_{k,h}^{s,t}$	=	An X by 2 matrix (where $X <= \sum_{p=1toN}(M_{k,h}^{p,t})$, defined in section 'B.3 Pseudo Unit Specific Variables') of *price-quantity pairs* formed from the *price* and the *incremental ST quantity* from all the calculated *day-ahead ST price curves* 'ST_PC' for *market participant* 'k' associated to *ST delivery point* 's' during *metering interval* 't' of *settlement hour* 'h'

Note: m1 is the number rows in ST_PC from *PSU*1, and similarly m2 from *PSU*2, m3 from *PSU*3, and m4 from *PSU*4.

PQ Pair Matrix (assuming 4 included *PSU*s)	=	Price [Row 'i', Column 1]	Quantity [Row 'i', Column 2]
$S\_ST\_PC_{k,h}^{s,t}$	Rows i=1 to m1, j=1 to m1	$ST\_PC[j,1]_{k,h}^{p1,t}$	$ST\_PC_{k,h}^{p1,t}$
	Rows i=(m1+1) to (m1+m2), j=1 to m2	$ST\_PC[j,1]_{k,h}^{p2,t}$	$ST\_PC_{k,h}^{p2,t}$
	Rows i=(m2+1) to (m1+m2+m3), j=1 to m3	$ST\_PC[j,1]_{k,h}^{p3,t}$	$ST\_PC_{k,h}^{p3,t}$
	Rows i=(m3+1) to (m1+m2+m3+m4), j=1 to m4	$ST\_PC[j,1]_{k,h}^{p4,t}$	$ST\_PC_{k,h}^{p4,t}$

The single ST price curve is sorted by increasing price. If the single ST price curve has *offers* at the same price (due to multiple *PSU*s with *offers* at the same price) then the equally priced laminations are aggregated into one PQ pair, leaving X <= ($M_{k,h}^{p1,t}$ + $M_{k,h}^{p2,t}$ + $M_{k,h}^{p3,t}$ + $M_{k,h}^{p4,t}$) rows in the single ST price curve. Once all equally priced laminations are aggregated, any remaining PQ pairs with a zero quantity will be removed and a PQ pair will be inserted into the first row, the delta quantity value of this PQ pair will be equal to zero, and the price will be set to the price of the PQ pair in row 2.

Finally, to form the N by 2 matrix (where N=X+1) called the derived interval price curve for the ST, the delta quantities in the single ST price curve must be converted back to total quantity values up to each price (i.e. from 1 up to each row i, i = 1 to N).

Price Curve Matrix	=	Price [Row 'i', Column 1]	Quantity [Row 'i', Column 2]
$DIPC_{k,h}^{s,t}$	Row i	$S\_ST\_PC[i,1]_{k,h}^{s,t}$	$\sum_{j=1}^{i} S\_ST\_PC[j,2]_{k,h}^{s,t}$

– End of Section –

Appendix C: DIGQ Formulation

C.1 Input Variables, Data and Information

The *PSU* resources are referred to as the set **PSU** = {p1,…,pN}, where N is the number of CT units, CT resources as the set **CT** = {c1,…,cN}, and, the ST resource as **ST** = {s}.

C.2 Registered Facility Variables

The following variables are on a *registered facility* basis so will apply to the CT and ST delivery points.

$DIPC_{k,h}^{m,t}$	=	*energy* price curves derived per interval from submitted hourly day-ahead *PSU energy offers*, represented as a N by 2 matrix of *price-quantity pairs* for each *market participant* ‘k’ at *delivery point* ‘m’ (where ‘m’ is a CT or ST delivery point) during *metering interval* ‘t’ of *settlement hour* ‘h’ arranged in ascending order by the offered price in each *price quantity pair* where offered prices ‘P’ are in column 1 and offered quantities ‘Q’ are in column 2

$MLP_{k,h}^{m,t}$	=	minimum output of *energy* the *market participant* ‘k’ at *delivery point* ‘m’ can maintain without ignition support in *metering interval* ‘t’ of *settlement hour* ‘h’

C.3 Pseudo Unit Specific Variables

The following variables are on a *pseudo unit* basis so will apply to the *PSU* delivery points.

$DRRQ_{k,h}^{p,t}$	=	quantity of *energy* scheduled in day-ahead in the MLP and dispatchable operating regions for *market participant* ‘k’ at *PSU* ‘p’ in *metering interval* ‘t’ of *settlement hour* ‘h’

$DA\_DQSI_{k,h}^{p,t}$	=	day-ahead constrained quantity scheduled for injection by *market participant* ‘k’ at *PSU* ‘p’ during *metering interval* ‘t’ of *settlement hour* ‘h’

$ORRQ_{k,h,d}^{p,t}$	=	The DGD calculated *PSU* operating region range quantity for *market participant* ‘k’ at *PSU* ‘p’ in *range* ‘d’ during *metering interval* ‘t’ of *settlement hour* ‘h’

$ST\_Portion_{k,d}^{p}$	=	The DGD calculated ST Portion, representing the percent of the *PSU energy* that belongs to the ST for *market participant* ‘k’ at *PSU* ‘p’ in *range* ‘d’

C.4 Calculated Variables

DIGQ: The day-ahead ST schedule used for *dispatch* includes the ST Portions of all scheduled *PSU*s, but for calculation of the DA-PCG only the eligible ST Portions are included. The derived interval guaranteed quantity for the ST is the sum of the ST Portion of the day-ahead *PSU* Schedules from all the *PSU*s where the associated CT is injecting *energy* in that interval.

Calculated as,

$$\sum_{p=1}^{N}[min(Day\ ahead\ PSU\ schedule, ORRQ\ for\ the\ MLP) \times ST\ Portion\ for\ the\ MLP$$
$$+\ max(min(ORRQ\ for\ the\ Dispatchable\ \ Region, Dispatchable\ Region\ Range\ Quantity$$
$$-\ ORRQ\ for\ the\ MLP), 0) \ \ \times ST\ Portion\ for\ the\ Dispatchable\ Region$$
$$+\ max((Day\ ahead\ PSU\ schedule - \ Dispatchable\ Region\ Range\ Quantity)$$
$$\times ST\ Portion\ for\ Duct\ Firing],0)$$

Defined as:

$DIGQ_{k,h}^{\ p,t}$	=	The portion of the day-ahead constrained quantity scheduled for injection that is eligible for DA-PCG for *market participant* ‘k’ at *PSU* ‘p’ during *metering interval* ‘t’ of *settlement hour* ‘h’

$DIGQ_{k,h}^{\ p,t}$	=	$\sum_{p=1}^{N}(\min(\mathrm{DA\_DQSI}_{k,h}^{p,t}, \mathrm{ORRQ}_{k,1}^{p}) \times \mathrm{ST\_Portion}_{k,1}^{p} + \max(\min(\mathrm{ORRQ}_{k,h,d2}^{p,t}, \mathrm{DRRQ}_{k,h}^{p,t} - \mathrm{ORRQ}_{k,h,d1}^{p,t}),0) \times \mathrm{ST\_Portion}_{k,d2}^{p} + \max\left(\left(\mathrm{DA}_{\mathrm{DQSI}}{}_{k,h}^{p,t} - \mathrm{DRRQ}_{k,h}^{p,t}\right), 0\right) \times \mathrm{ST\_Portion}_{k,d3}^{p})$

Where:

N	=	The number of DA-PCG eligible *PSU*s

– End of Section –

Appendix D: Determining OPCAP

The operating capacity (OPCAP) required in the calculation of DA-PCG component 2 will be derived from the *generator outages* and derates that were used for each *dispatch interval* by the DSO tool. The OPCAP data will be stored in MIM and available for *settlement* calculations.

An OPCAP value will only exist if there is an *outage*/derate for a particular *generator* for the interval in question. If there are no *outages*/derates for a *generator* in a *dispatch interval*, no record will be available. For *dispatch intervals* where OPCAP was not derived due to a *planned outage* or *forced outage* to software, hardware or communication systems, a null will be utilized as the OPCAP value.

– End of Document –