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Market Renewal Program: Market Settlements

Settlements Rules and Manuals (Part 1 of 3)

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Meeting Purpose and Agenda

Purpose: Prepare stakeholders for their review of the proposed market rules and market manuals that codify the Market Settlements detailed designs

Agenda:

- Brief overview of conforming changes to Market Entry obligations and procedures
- Overview of structure and content of the proposed market rules and market manuals for Settlements and Billing
- Review basic examples of settlement amounts

Approach

- Market settlements is by nature very calculations-heavy
- To assist in understanding, the IESO has prepared a number of examples for stakeholder review
- To further aid synthesis of the rules, or to aid broader understanding of Market Renewal, stakeholders are encouraged to ask for additional scenarios and examples

Engagement Timeline

December 1: Materials posted for stakeholder review

December 14: Introduction and discussion with participants

Throughout December and January: Stakeholders can request additional examples or scenarios through engagement@ieso.ca

Mid-January: Segmented discussions with stakeholders to review examples/scenarios

February 21: Comments/feedback on market rules and market manuals due to IESO

Segmented Stakeholder Discussions

The IESO will host stakeholder meetings in mid-January for market participants to review the base-case(s) and answer any additional participant questions relating to settlement

Meetings dates/times are posted on the Market Renewal Implementation webpage for stakeholder sign-up: https://www.ieso.ca/en/Market-Renewal/Stakeholder-Engagements/Implementation-Engagement-Market-Rules-and-Market-Manuals

Conforming Changes to Market Entry Obligations and Procedures

Background: Shared Daily Energy

Market Entry and Prudential Market Rules

- Introduced the registered shared daily energy limit (DEL)

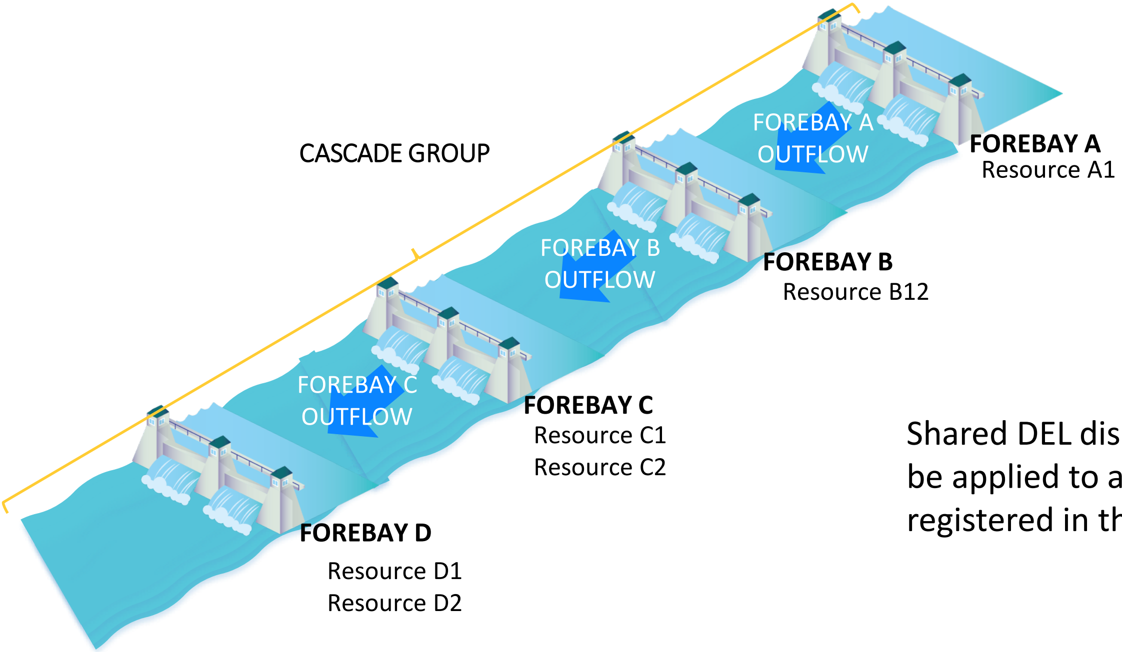
Settlement Market Rules

- Replaces registered shared DEL with registered cascade groups and forebays
- Registration of a cascade group and set of forebays automatically sets the linked resources for a shared DEL

Key Changes

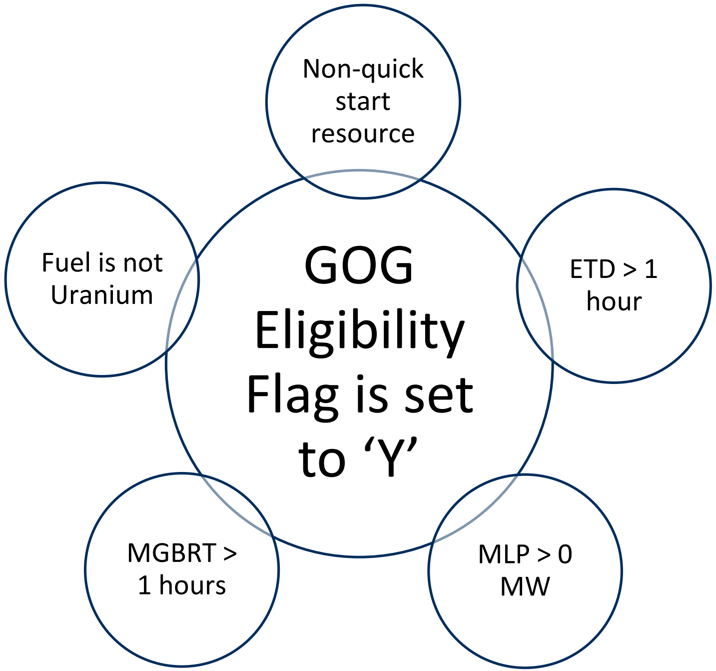
- Registration of a cascade group and set of forebays and their associated resources automatically sets the linked resources for a shared DEL
- IESO will establish these groups and linkages based on consultation with the MP when determining resources for a facility
  - Registered information; expect infrequent changes
- Removing a resource from a forebay removes it from the cascade group, linked forebay
  - Resource will be considered individually instead of part of the group

Example



Shared DEL dispatch data will be applied to all resources registered in the cascade group

GOG Eligibility



- Market Entry and Prudential Market Rules indicated the market participant needs to request GOG eligibility status
- No longer require market participants to request GOG eligibility
- IESO will automatically register eligibility if all the conditions are met

Market Settlements: Batch Summary

Market Rules and Market Manuals

Impacted Market Rules and Manuals

Market Rules	
Market rule provisions that describe financial obligation arising from the IESO-administered market, including new defined terms	Chapter 9, Settlements and Billing Chapter 9, Appendix 9.1 VEE Process Chapter 9, Appendix 9.2 Data Inputs and Variables (New) Chapter 9, Appendix 9.3 Pseudo-Unit Translations (New) Chapter 9, Appendix 9.4 Settlement Mitigation (New)

Market Manuals	
Market procedures and standards that describe the settlement process of the IESO-administered market	Market Manual 5.3 Physical Bilateral Contract Data Market Manual 5.5 IESO-Administered Markets Settlement Amounts (Renamed) Market Manual 5.6 Non-Market Settlement Programs (New) Market Manual 5.7 Settlement Process Market Manual 5.8 Settlement Invoicing Market Manual 5.10 Settlement Disagreements IESO Charge Types and Equations

Market Manual Timelines

December 1

- MM 5.5 IESO-Administered Markets Settlement Amounts
- MM 5.3 Physical Bilateral Contract Data

RSS Release

- MM 5.7 Settlement Process
- MM 5.8 Settlement Invoicing
- MM 5.10 Settlement Disagreements

Future Batch(TBD)

- MM 5.6 Non-Market Settlement Programs
- IESO Charge Types and Equations

Market Rules: Chapter 9 Sections

- Introduction
- Settlement Data Collection and Management
- Hourly Settlement Amounts
- Non-Hourly Settlement Amounts
- Market Power Mitigation
- Settlement Statements

Section Overview

- The focus of the engagement will be on three main sections: Hourly, Non-Hourly Settlement amounts and Market Power Mitigation
- Each section will include:
  - Background information on each settlement amount
  - Key changes or clarification to the design
  - Relevant examples to facilitate further understanding of the market rules

Sections and Settlement Amounts

Hourly Settlement Amount

- Two-Settlement
- Non-Dispatchable Resources
- DAM Balancing Credit
- DAM Make-Whole Payment
- Real-Time Make-Whole Payment
- Real-Time Intertie Offer Guarantee
- Real-Time Intertie Failure Charge
- Transmission Rights
- Hourly Uplifts

Non-Hourly Settlement Amounts

- DAM Generator Offer Guarantee
- Real-Time Generator Offer Guarantee
- Real-Time Ramp Down Settlement Amount
- Internal Congestion & Loss Residuals
- Real-Time External Congestion, Day-Ahead & Real-Time NISL Residual
- Generator Failure Charge
- Fuel Cost Compensation
- Non-Hourly Uplifts

Market Power Mitigation

- Mitigation of Settlement Amounts
- Day-Ahead Market Reference Level Settlement Charge
- Real-Time Market Reference Level Settlement Charge

Market Rule Chapter 9 Section Summary: Hourly Settlement Amounts

Hourly Settlement Amounts: Two-Settlement

Background: Two-Settlement

- Two-Settlement is the settlement of the day-ahead market (DAM) and real-time market (RTM) for energy and operating reserve
- Settlement applies to:
    - dispatchable resources including new virtual transactions and price responsive load (PRL); and
    - non-dispatchable resources (modified two-settlement)

DAM Settlement and Real-Time Balancing Settlement

DAM Settlement

- Paid or charged the DAM scheduled quantity for energy and operating reserve at the applicable DAM locational marginal price (LMP) on an hourly basis

Real-Time Balancing Settlement

- Balance any **deviations** between the day-ahead market and the real-time market
- Paid or charged at the applicable real-time market locational marginal price if the actual energy consumed or produced, or operating reserve offered, differs from the DAM scheduled quantity at the 5-min interval basis

Two-Settlement Mechanics – Dispatchable Resource

	Day-Ahead		Real-Time (Balancing)
	$Q_{DA} \times LMP_{DA}$	+	$(Q_{RT} - Q_{DA}) \times LMP_{RT}$
Loads and exports	1 - Pay for day-ahead scheduled withdrawals		1 - Pay for incremental real-time withdrawals 2 - Are paid for unconsumed day-ahead scheduled withdrawals (sell-back)
Generators and imports	1 - Are paid for day-ahead scheduled injections		1 - Are paid for incremental real-time injections 2 - Pay for undelivered day-ahead scheduled injections (buy-back)

Two Settlement Example – Dispatchable Generator

Day-Ahead		Real-Time (Balancing)
$Q_{DA} \times LMP_{DA}$	+	$(Q_{RT} - Q_{DA}) \times LMP_{RT}$
DAM schedule: 150 MW DAM price: $25		Actual injection: 100 MW Real-time market price: $30
$Q_{DA} \times LMP_{DA}$ = 150 MW x $25 = $3750		$(Q_{RT} - Q_{DA}) \times LMP_{RT}$ = $\boxed{\text{(100 MW – 150 MW)}}$ x $30 = -$1500

Dispatchable generator must buy back undelivered DAM MWs at the real-time locational marginal price

Net Energy Settlement = $2250

Two-Settlement Charges

Energy Charges

- CT 1100 – Day-Ahead Market Settlement Amounts for Dispatchable Generator
- CT 1101 – Real-Time Market Settlement Amounts for Dispatchable Generator
- CT 1102 – Day-Ahead Market Settlement Amounts for Dispatchable Loads
- CT 1103 – Real-Time Market Settlement Amounts for Dispatchable Loads
- CT 1110 – Day-Ahead Market Settlement Amounts for Imports
- CT 1111 – Real-Time Market Settlement Amounts for Imports
- CT 1112 – Day-Ahead Market Settlement Amounts for Exports
- CT 1113 – Real-Time Market Settlement Amounts for Exports

Two Settlement – Operating Reserve

Day Ahead		Real-Time (Balancing)
Q_{DA} x OR_LMP_{DA}	+	$(Q_{RT} – Q_{DA})$ x OR_LMP_{RT}

Q_{DA} = day-ahead market operating reserve scheduled quantities

Q_{RT} = real-time market actual operating reserve quantities

OR_LMP_{DA} = day-ahead market locational marginal price of OR (hourly)

OR_LMP_{RT} = real-time market locational marginal price of OR (5-minute)

Example of OR Activation for Dispatchable Generator

Energy

Day-Ahead

DAM schedule: 100 MW
DAM price: $20

= 100 MW x $20
= $2000

Real-Time (Balancing)

Actual injection: 130 MW*
Real-time market price: $60

***Dispatched up for 30MW due to OR Activation**

= (130 MW – 100 MW) x $60
= $1800

Net Energy Settlement
$2000 + $1800 = $3800

Operating Reserve

Day-Ahead

DAM schedule: 30 MW
DAM price: $3

= 30 MW x $3
= $90

Real-Time (Balancing)

Dispatch to 0MW* at $30

*OR Activated 30 MW

= (0 MW – 30 MW) x $30
= -$900

Net Operating Reserve Settlement
$90 + (-$900) = -$810

Total Two-Settlement
$2990

Two-Settlement Charges

Operating Reserve Charges

- CT 212 – Day-Ahead Market 10-Minute Spinning Reserve Settlement Credit
- CT 213 – Real-Time 10-Minute Spinning Reserve Settlement Credit
- CT 214 – Day-Ahead Market 10-Minute Non-Spinning Reserve Settlement Credit
- CT 215 – Real-Time 10-Minute Non-Spinning Reserve Settlement Credit
- CT 216 – Day-Ahead Market 30-Minute Operating Reserve Settlement Credit
- CT 217 – Real-Time 30-Minute Operating Reserve Settlement Credit

Virtual Transactions

- Submit bids and offers just like physical resources to purchase or sell energy in DAM;
- Are different from physical resources in that they do not require physical delivery or consumption in real-time;
- Cannot participate in the operating reserve market;
- Are only settled for energy using their DAM schedule; and
- Will be settled under the following 4 charges:
  - CT 1106 – Day-Ahead Market Settlement Amounts for Virtual Transaction to Sell
  - CT 1107 – Real-Time Market Settlement Amounts for Virtual Transaction to Sell
  - CT 1108 – Day-Ahead Market Settlement Amounts for Virtual Transaction to Buy
  - CT 1109 – Real-Time Market Settlement Amounts for Virtual Transaction to Buy

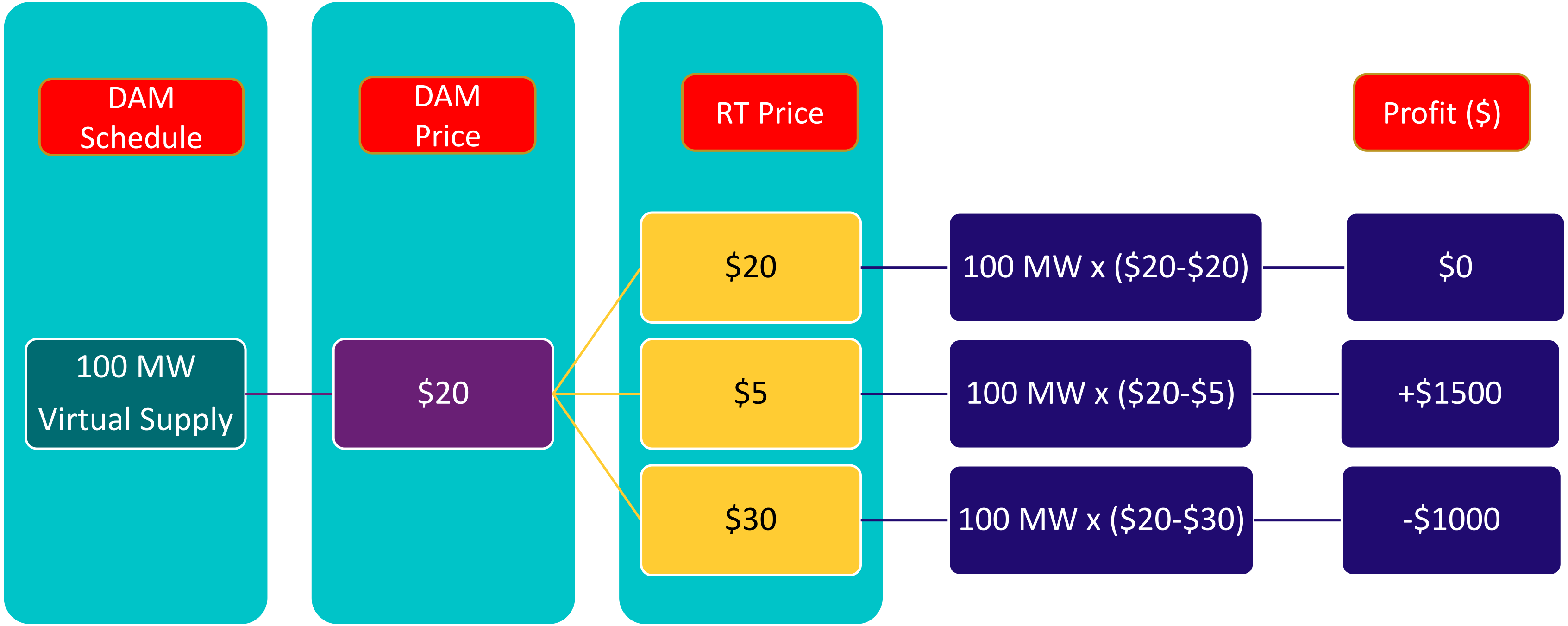
Two-Settlement Mechanics – Virtual

Day-Ahead		Real-Time (Balancing)
Q_{DA} x LMP_{DA}	+	$(Q_{RT} - Q_{DA})$ x LMP_{RT}
Q_{DA} x LMP_{DA}		$(0 - Q_{DA}$) x LMP_{RT}

Two-Settlement of Virtual Transactions can be simplified to:

Q_{DA} x $(LMP_{DA} - LMP_{RT})$

Example - Virtual Transaction Profit/Loss



Price Responsive Loads (PRL)

Price responsive load is a new load resource type that:

- can submit bids in DAM;
- are not dispatchable in real time;
- are scheduled only for energy; and
- are settled at the locational marginal price in both DAM and RT

Price responsive loads will be settled under the following two charges:

- CT 1104 – Day-Ahead Market Settlement Amounts for Price Responsive Loads
- CT 1105 – Real-Time Market Settlement Amounts for Price Responsive Loads

Two-Settlement Mechanics – PRLs

Day-Ahead		Real-Time (Balancing)
$Q_{DA} \times LMP_{DA}$	+	$(Q_{RT} - Q_{DA}) \times LMP_{RT}$
Q_{DA} = day-ahead market scheduled quantities		Q_{RT} = real-time market actual consumption
LMP_{DA} = day-ahead market locational marginal price (hourly)		LMP_{RT} = real-time market locational marginal price (5-minute)

Physical HDR associated with PRL

- Physical HDR that are registered as PRLs will receive separate energy schedules for HDR and associated PRL under different delivery points
- Physical HDR and associated PRL resource consumption will be measured under the same metering point, and thus are settled together under the delivery point for the associated PRL

Two-Settlement Mechanics – PRL with HDR

Day-Ahead

$$(Q_{DA} + Q_{DA\_HDR}) \text{ x } LMP_{DA}$$

+

Real-Time (Balancing)

$$(Q_{RT} - Q_{DA} - Q_{DA\_HDR}) \text{ x } LMP_{RT}$$

Q_{DA} = day-ahead market scheduled quantities for PRL

Q_{DA_HDR} = day-ahead hourly demand response quantity scheduled

LMP_{DA} = day-ahead market locational marginal price (hourly)

Q_{RT} = real-time market actual consumption at the PRL delivery point

LMP_{RT} = real-time market locational marginal price (5-minute)

Hourly Settlement Amounts:
Hourly Physical Transaction Settlement Amount - Non-Dispatchable Resources

Non-Dispatchable Generators

Settlement of energy will be based on the actual quantity of energy injected at the delivery point, multiplied by the applicable real-time market locational marginal price

$$Q_{RT} \text{ x } LMP_{RT}$$

Non-dispatchable generators will be settled under charge type 1114 – Non-Dispatchable Generator Energy Settlement Amount

Non-Dispatchable Loads

- The IESO forecasts demand quantities for non-disatchable loads (NDLs) and calculates the DAM Ontario Zonal Price (OZP)
- NDLs will only be exposed to settlement when they actually consume energy in real-time
- NDLs will be settled based on the DAM Ontario Zonal Price plus load forecast deviation charge at the real-time energy consumption
- NDL settlement excludes PRLs

Load Forecast Deviation Charge

- Total value of the IESO's forecast deviation for all NDLs in dollars per MWh for a given settlement hour
- A function of the total sum of forecast deviations at every NDL location and the sum of DAM to RTM price differences at each NDL location, calculated as two components:
  - Real-Time Purchase Cost/Benefit
  - DAM Volume Factor Cost/Benefit

Forecast Deviation Components

Component	Description
Real-time Purchase Cost/Benefit	• represents the total hourly $ cost or benefit, arising from DAM load forecast deviations in the real-time market • calculated as the difference between the actual energy consumed by non-dispatchable loads in real time and the DAM load forecast, multiplied by the real-time market LMP $= LMP_{RT} \times (Q_{RT} - Q_{DAM\ Forecast})$
DAM Volume Factor Cost/Benefit	• represents the total hourly cost or benefit to all non-dispatchable loads, arising from DAM load forecast deviations in the DAM • calculated as the difference between the DAM load forecast and the actual energy consumed by non-dispatchable loads, multiplied by the Ontario zonal price $= OZP_{DAM} \times (Q_{DAM\ Forecast} - Q_{RT})$

Load Forecast Deviation Charge

- The sum of two components is allocated over the total real-time energy withdrawn by all NDLS, resulting in the load forecast deviation charge (LFDC), expressed in \$/MWh
- The load forecast deviation charge can be a positive or negative value

$$LFDC = \frac{\text{(Real-Time Purchase Cost/Benefit) + (DAM Volume Factor Cost/Benefit)}}{\text{real-time energy withdrawn by all NDLs}}$$

Settlement - Non-Dispatchable Loads

$$Q_{RT} \text{ x } (OZP_{DAM} + LFDC)$$

Q_{RT} = real-time market actual consumption (AQEW- AQEI)

OZP_{DAM} = day-head Ontario zonal price

LFDC = load forecast deviation charge

Non-Dispatchable Loads will be settled under charge type 1115 – Non-Dispatchable Load Energy Settlement Amount

Hourly Settlement Amounts: Day-Ahead Balancing Credit

Background: DAM Balancing Credit (DAM_BC)

- Offsets any negative buyback incurred as a result of following IESO dispatch instruction in RT due to a reliability need
- Applied in RT when the IESO curtails imports and exports, or de-commits GOG-eligible resources after it receives a DAM schedule
- A resource will not be eligible for DAM Balancing Credit payment if:
  - it does not follow dispatch instructions
  - it was constrained on request from market participant, to prevent endangering the safety of any person, or equipment damage, or violation of any applicable law
  - it received a RT_MWP for the same interval
- These amounts will be settled under charge type 1815 – Day-Ahead Market Balancing Credit

DAM Balancing Credit – Key Changes

- DAM Balancing Credit for GOG-eligible resources is calculated as:

DAM_BC = Balancing credit for energy (BCE) +Balancing credit for OR

- BCE was revised from detailed design to align with the two-settlement equations (s 3.3.3)

Old equation:

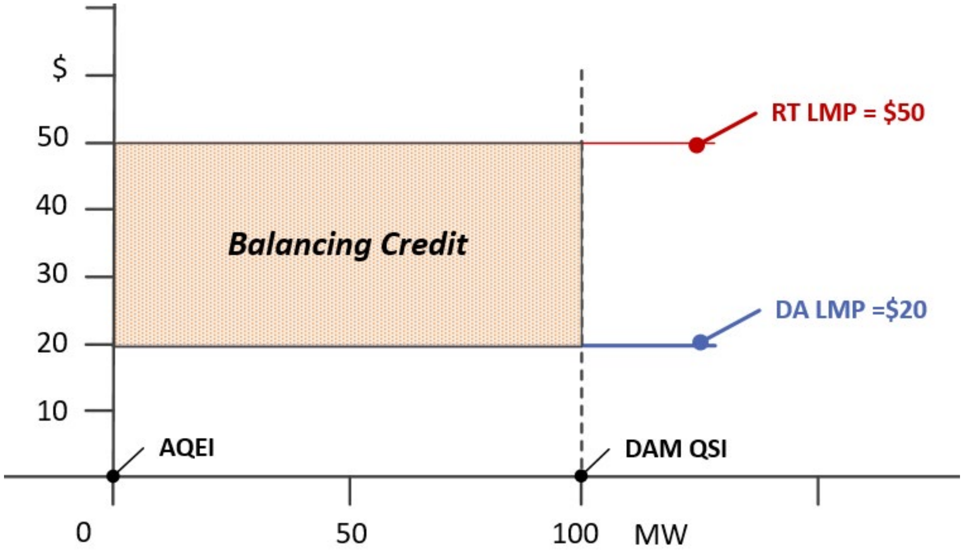
$$BCE_{k,h}^{m} = \sum^{T} MAX\left[0, \left(RT\_LMP_{h}^{m,t} - DAM\_LMP_{h}^{m}\right) \times MAX\left(0, \left(DAM\_QSI_{k,h}^{m} - RT\_QSI_{k,h}^{m,t}\right)\right)\right]/12$$

New equation:

$$BCE_{k,h}^{m} = \sum^{T} MAX\left[0, \left(RT\_LMP_{h}^{m,t} - DAM\_LMP_{h}^{m}\right) \times MAX\left(0, \left(DAM\_QSI_{k,h}^{m} - AQEI_{k,h}^{m,t}\right)\right)\right]/12$$

DAM Balancing Credit – Scenario 1

Scenario 1: GOG-eligible resource is de-committed in RT after it received a DAM schedule



BCE = (RT LMP – DAM LMP) x (DAM QSI – AQEI)

=($50 - $20) x (100 MW – 0)

= $30 x 100 MW

= $3000

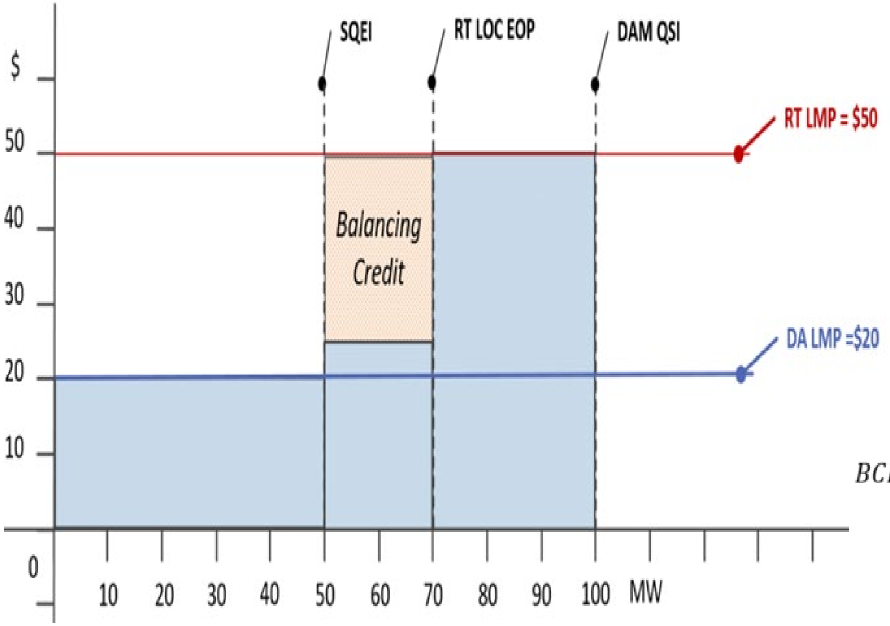
DAM_BC of $3000 would be paid to the GOG-eligible resource to cover buyback cost incurred as a result of being de-committed by IESO

DAM Balancing Credit – Imports and Exports

- DAM Balancing Credit for imports and exports will be adjusted if the resource increases its offer or decrease its bid in real-time relative to DAM LMP
- DAM BC excludes any negative buy-back incurred for the portion of DAM schedule that would not have been scheduled in RT due to the increase in offer or decrease in bid
- This rules applies to both energy and operating reserve

DAM Balancing Credit – Scenario 2

Scenario 2: Import is curtailed in RT after it received a DAM schedule



DAM Energy Offers – Dispatch Data (DAM BE)		
PQ #	Price ($/MWh)	Quantity (MW)
1	10	0
2	10	100

RT Energy Offers – Dispatch Data (BE)		
PQ #	Price ($/MWh)	Quantity (MW)
1	20	0
2	20	50
3	25	70
4	50	100

*Assume there are no operating reserves
BCE is calculated as:

Negative buyback

$$BCE^{i}_{k,h} = Max\Big[0, \sum^{T}\big(Min(RT\_LOC\_EOP^{i,t}_{k,h}, DAM\_QSI^{i}_{k,h}) - SQEI^{i}_{k,h}\big)\, x\, \big(RT\_LMP^{i,t}_{h} - DAM\_LMP^{i,t}_{h}\big) + OP\big(DAM\_LMP^{i,t}_{h}, Min(RT\_LOC\_EOP^{i,t}_{k,h}, DAM\_QSI^{i}_{k,h}), BE^{i,t}_{k,h}\big)\Big] /12$$

Lost opportunity cost

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DAM Balancing Credit – Scenario 2 (Cont)

Negative buyback :

[Min(RT_LOC_EOP, DAM_QSI) – RT_QSI) x (RT_LMP – DAM_LMP)]

=(70MW - 50MW) x ($50 – $20)

= 20 x $30

= $600

Operating profit : OP(DAM_LMP, Min(RT_LOC_EOP, DAM_QSI), BE)

Revenue = 70 MW x 20 = $1400

Cost = (50MW x $20) + (20MW x $25)

= $1500

Net Amount = ($1400 - $1500) = -$100

BCE = $600 - $100 = $500

Result:
Negative buyback was reduced by $100 which represents the lost opportunity cost.

Importer will receive a payment of $500 as CT 1815 on its settlement statement

Hourly Settlement Amounts:
Day-Ahead Market Make-Whole Payment

Background: DAM Make-Whole Payment (DAM_MWP)

- Provides compensation for any shortfall in payment incurred by a resource that was scheduled above its economic operating point in DAM for energy and operating reserve
- Does not apply to ramp-up period for NQS resources, resource associated with called capacity or portion of the dispatchable load that was bid at $2000
- All dispatchable resources, price responsive loads and self-scheduling electricity storage resources that are injecting energy are eligible for DAM_MWP
- DAM_MWP will be settled as the following charges:

1800	Day-Ahead Market Make-Whole Payment - Energy
1801	Day-Ahead Market Make-Whole Payment - 10-Minute Spinning Reserve
1802	Day-Ahead Market Make-Whole Payment - 10-Minute Non-Spinning Reserve
1803	Day-Ahead Market Make-Whole Payment - 30-Minute Operating Reserve

DAM_MWP – Key Changes

- Added new rules (s 3.4.3), consistent with the principle in the current market to minimize uplift costs to Ontario consumers, negative offers and bids will be adjusted when calculating DAM_MWP as follows:
  - offers will be limited to lesser of $0.00 and DAM LMP
  - bids will be limited to lesser of replacement bid price and DAM LMP (where bid is less than replacement price -$15/MWh for dispatchable loads and -$125/MWh for exports)
- Added new ineligibility rules for:
  - boundary entity resources that have a linked wheeling through transaction (s 3.4.4.3)
  - dispatchable loads that offer a portion of their energy at $2000 (s 3.4.4.5)
  - resources with binding combined cycle physical unit constraint (s 3.4.4.6)

DAM_MWP – Key Changes (cont'd)

- A hydroelectric generation resource will not be eligible for the energy component of DAM_MWP if:
  - It is scheduled across the trade day at MinDEL; or
  - The sum of the energy schedule for the trading day across all generation resources that share a forebay equals MinDEL (s 3.4.5)
- New equations for Forbidden Region Operating Profit, which is used to adjust DAM_MWP to avoid over-compensation (s 3.4.13.2)
- New equations for hydroelectric generation resources with start restrictions (s 3.4.13.4)
- Examples are provided in MM 5.5 and "Day-Ahead and Real-time make-whole payment for hydroelectric generation facilities" presentation on August 25, 2022

DAM_MWP – Scenario 1

Scenario 1: Generator is scheduled uneconomically above its economic operating point (EOP) in DAM for both energy and operating reserve in HE3

DAM Energy & OR Offers (DAM_BE & DAM_BOR)		
PQ #	Price ($/MWh)	Quantity (MW)
1	10	0
2	10	100
3	20	200
4	30	300
5	40	400

DAM Schedules	Quantity (MW)
Energy	
DAM_QSI	250
DAM_EOP	200
Operating reserve	
DAM QSOR (10S)	200
DAM_OR_EOP	100

DAM Prices	$
DAM_LMP	$20
DAM_PROR	$11

DAM_MWP = DAM_COMP1 + DAM_COMP2

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DAM_MWP – Scenario 1

Energy (DAM_COMP1)

DAM_COMP1 = -1 x [OP(DAM_QSI) – OP(DAM_EOP)]		
	OP (DAM_QSI)	**OP (DAM_EOP)**
Revenue	250MW x $20 = $5000	200MW x $20 = $4000
Costs	(100MW x $10) + (100MW x $20) + (50MW x $30) = $4500	(100MW X $10) + (100MW x $20) = $3000
Net	$5000 - $4500 = $500	$4000 - $3000 = $1000
DAM COMP1	-1 x ($500 - $1000) = $500	

Operating Reserve (DAM_COMP2)

DAM_COMP2 = -1 x [OP(DAM_QSOR) – OP(DAM_OR_EOP)]		
	OP (DAM_QSOR)	**OP (DAM_OR_EOP)**
Revenue	200MW x $11 = $2200	100MW x $11 = $1100
Costs	(100MW x $10) + (100MW x $20) = $3000	100MW x $10 = $1000
Net	$2200 - $3000 = -$800	$1100 - $1000 = $100
DAM COMP2	-1 x (-$800 - $100) = $900	

DAM_MWP – Scenario 1

DAM_MWP =	Max (0, DAM_COMP1 + DAM_COMP2)
DAM_MWP =	Max (0, 500 + 900) = $1400

DAM_MWP is a positive amount, therefore the following amounts will appear on the generator settlement statement:

Settlement amounts on Settlement Statement		
1800	Day-Ahead Market Make-Whole Payment - Energy	$500
1801	Day-Ahead Market Make-Whole Payment - 10-Minute Spinning Reserve	$900

Hourly Settlement Amounts:
Real-Time Market Make-Whole Payment

Background: Real-Time Make-Whole Payment (RT_MWP)

- Provides compensation when a resource deviates from its EOP in response to dispatch instruction or when the resource is scheduled uneconomically due to differences between scheduling and pricing pass
- Resources that are eligible for RT_MWP may be able to recover lost cost and lost opportunity cost for energy and operating reserve
- RT_MWP is calculated as:

$$RT\_MWP = Max(0, ELC + OLC) + Max(0, ELOC + OLOC)$$

Background: Real-Time Make-Whole Payment (RT_MWP)

Real-Time Make-whole payment will be settled under the following 8 new charges:

Lost Cost

1900	Real-Time Make-Whole Payment - Lost Cost for Energy
1901	Real-Time Make-Whole Payment - Lost Cost for 10-Minute Spinning Reserve
1902	Real-Time Make-Whole Payment - Lost Cost for 10-Minute Non-Spinning Reserve
1903	Real-Time Make-Whole Payment - Lost Cost for 30-Minute Operating Reserve

Lost Opportunity Cost

1904	Real-Time Make-Whole Payment - Lost Opportunity Cost for Energy
1905	Real-Time Make-Whole Payment - Lost Opportunity Cost for 10-Minute Spinning Reserve
1906	Real-Time Make-Whole Payment - Lost Opportunity Cost for 10-Minute Non-Spinning Reserve
1907	Real-Time Make-Whole Payment - Lost Opportunity Cost for 30-Minute Operating Reserve

Real-Time Make-Whole Payments – Key Changes

- Added new eligibility rules for exports to recover lost cost for operating reserves (s 3.5.8)
- Added new rules (s 3.5.5), consistent with the principle in the current market to minimize uplift costs to Ontario consumers, negative offers and bids will be adjusted when calculating RT_MWP as follows:
  - offers will be limited to lesser of $0.00 and RT LMP
  - bids will be limited to lesser of replacement bid price and RT LMP (where bid is less than replacement price -$15/MWh for dispatchable loads and -$125/MWh for exports)
- Added new ineligibility rules for resources with binding combined cycle physical unit constraint (s 3.5.4.1b)

Real-Time Make-Whole Payments – Key Changes (Cont)

Added new ineligibility rules for dispatchable loads, consistent with the principles of the current market:

- Portion of energy bid at $2000 are ineligible for lost cost and lost opportunity cost for energy (s 3.5.4.1a)
- Lost opportunity cost and lost cost for energy will not be paid when energy bid for an hour is not the same as the preceding or next hour and such change results in ramping of the resource (s 3.5.4.4)
- Lost opportunity cost will not be paid when the dispatchable load deviates from dispatch or is unable to follow its dispatch instructions (s 3.5.4.7) unless the resource was:
  - activated for operating reserves
  - dispatch by IESO to maintain reliability

Real-Time Make-Whole Payment – Key Changes (cont'd)

- Added ineligibility rules for variable generation subject to release notification (s 3.5.2)
- A hydroelectric generation resource will not be eligible for the energy component of RT_MWP if:
  - It is scheduled across the trade day at MinDEL; or
  - The sum of the energy schedule for the trade day across all generation resources that share a forebay equals MinDEL (s 3.5.4)
- New equations for Forbidden Region Operating Profit, which is used to adjust RT_MWP to avoid over-compensation (s 3.5.6.1 & s 3.5.6.2)
- Refer to "Day-Ahead and Real-time make-whole payment for hydroelectric generation facilities" presentation on August 25, 2022

RT_MWP – Scenario 1

Scenario 1: The reliability max constraint is binding on the RT schedule for HE 3. This prevents the resource from achieving its EOP.

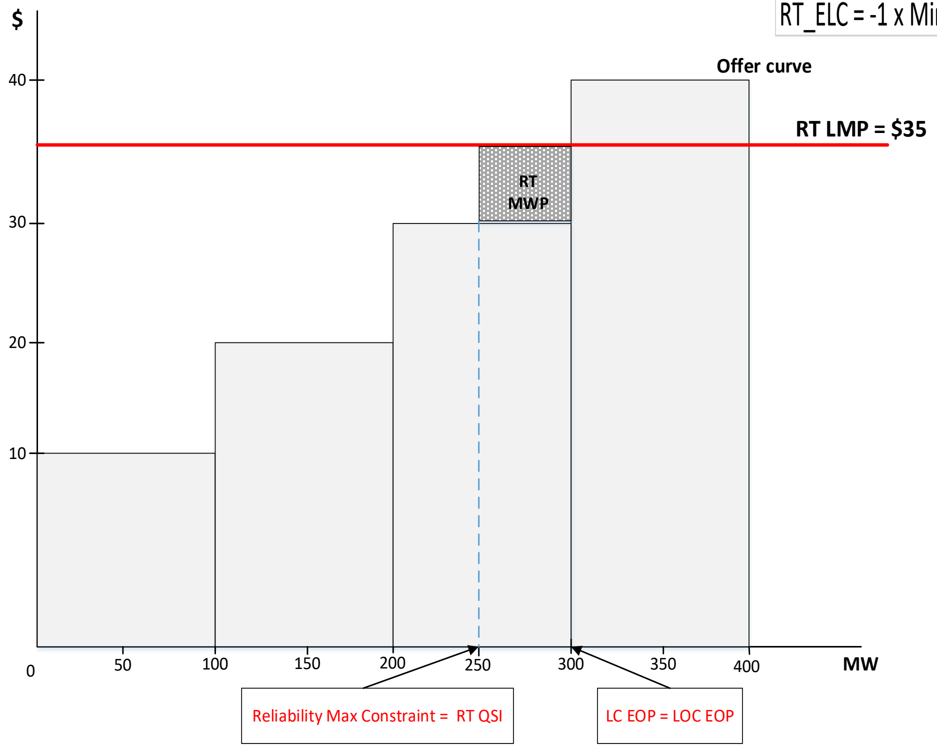
Energy Offers – Dispatch Data		
PQ #	Price ($/MWh)	Quantity (MW)
1	10	0
2	10	100
3	20	200
4	30	300
5	40	400

Schedules, EOP, AQEI, Constraints	
Type	Quantity (MW)
RT QSI	250 MW
AQEI	250MW
LC EOP	300 MW
LOC EOP	300 MW
Reliability Max	250 MW

RT Prices	$
RT LMP	$35

$$RT\_MWP = \sum^{T} Max(0, RT\_ELC + RT\_OLC) + Max(0, RT\_ELOC + RT\_OLOC)$$

RT_MWP – Scenario 1



RT_ELC = -1 x Min[0, OP(RT_LMP,Min(RT_QSI,AQEI),BE) - OP(RT_LMP, Max(RT_LC_EOP,DAM_QSI),BE)]

RT Lost Cost Calculation		
	OP (Min(RT_QSI, AQEI))	OP (RT_LC_EOP)
Revenue	250MW X $35 = $8750	300MW X $35 = $10,500
Costs	100MW X $10 + 100MW X $20 + 50MW X $30 =	100MW X $10 + 100MW X $20 + 100MW X $30 =
	$4,500	$6,000
Net	$8750 - $4500 = $4250	$10500 - $6000 = $4500
RT_ELC	-1 X MIN(0, $4250 - $4500) = $250	

Since LC_EOP > RT_QSI, resource is not eligible for RT ELC

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RT_MWP – Scenario 1

RT_ELOC = OP(RT_LMP,RT_LOC_EOP,BE) - Max(0,OP(RT_LMP,Max(RT_QSI,AQEI),BE))

RT Lost Opportunity Cost Calculation		
	OP (RT_LOC_EOP)	OP (Max(RT_QSI, AQEI))
Revenue	300MW X $35 = $10,500	250MW X $35 = $8,750
Costs	100MW X $10 + 100MW X $20 + 100MW X $30 =	100MW X $10 + 100MW X $20 + 50MW X $30 =
	$ 6,000	$ 4,500
Total	$10500 - $6000 = $4,500	$8750 - $4500 = $4,250
RT_ELOC	$4500 - $4250 = $250	

RT MWP = Max (0, RT_ELC + RT_OLC) + Max(0, ELOC + OLOC)
RT MWP = Max (0, $0) + Max(0, $250)
= $250

RT_MWP is a positive amount; hence the following settlement amounts will appear on the settlement statement for HE3

Settlement Amounts on Settlement Statement		
1900	Real Time Make-Whole Payment - Lost cost for Energy	$0
1904	Real Time Make-Whole Payment - Lost Opportunity Cost for Energy	$250

RT_MWP – Scenario 2

Scenario 2: Export is scheduled in PD with pricing discrepancy

Energy Bids – Dispatch Data		
PQ #	Price ($/MWh)	Quantity (MW)
1	40	0
2	40	100
3	30	200
4	20	300
5	10	400

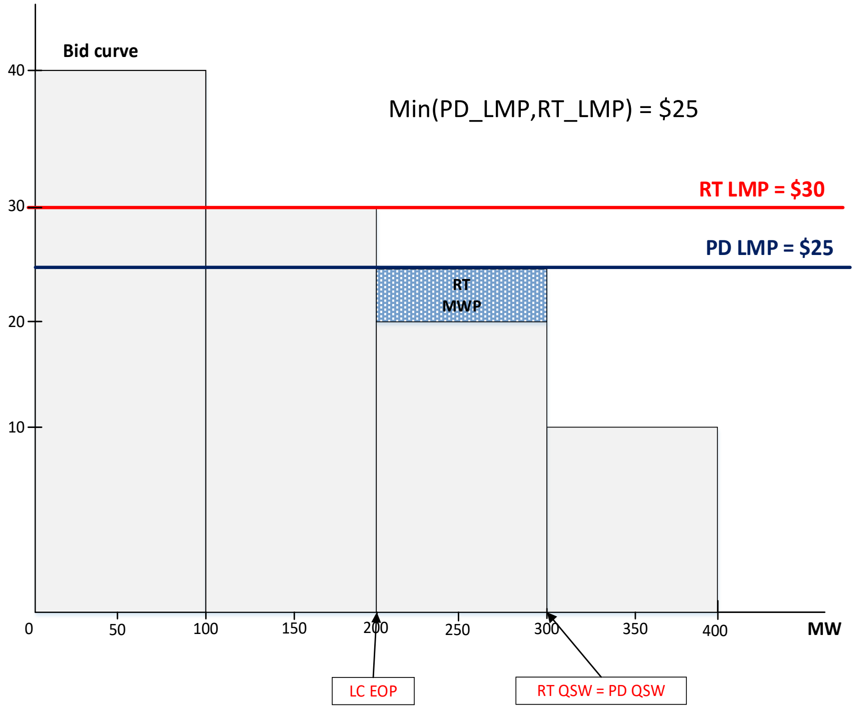
Schedules and EOP	
Type	Quantity (MW)
PD_QSW	300 MW
SQEW	300 MW
LC EOP	200 MW
LOC EOP	N/A
DAM_QSW	0 MW

$$RT\_MWP_{k,h}^{i} = \sum^{T} Max\left(0, RT\_ELC_{k,h}^{i,t} + RT\_OLC_{k,h}^{i,t}\right)$$

DAM Prices	$
PD LMP	$25
RT LMP	$30

The price in both the latest PD and RT exceeds the export bid cost, therefore the export will be compensated for lost cost based on min(PD_LMP, RT_LMP)

RT_MWP – Scenario 2



RT_ELC = OP(PD_LMP, Max(SQEW,DAM_QSW), BL) - OP(PD_LMP,Max(RT_LC_EOP,DAM_QSW) ,BL)

RT Energy Lost Cost Calculation		
	OP (Max(SQEW, DAM_QSW))	**OP (Max(RT_LC_EOP, DAM_QSW))**
Revenue	300MW X $25 = $7500	200MW x $25 = $5000
Costs	100MW X $40 + 100MW X $30 + 100MW X $20 =	100MW X $40 + 100MW X $30 =
	$9,000	$7,000
Net	$7500 - $9000 = -$1500	$5000 - $7000 = -$2000
RT_ELC	Max (0, -$1500 - -$2000) = $500	
RT MWP =	Max (0, RT_ELC + RT_ELOC)	
RT MWP =	Max (0, 500 + 0) = $500	

Result: The export will be paid RT_MWP $500 for lost cost

Hourly Settlement Amounts: Real-Time Intertie Offer Guarantee

Background: Real-Time Intertie Offer Guarantee

- Similar to the current market, RT IOG for import transactions will be offset where no net power is provided to the Ontario market
- The offset process will be applied to:
  - RT import transactions that are part of an implied wheel through transaction
  - RT import transactions when the market participant has DAM imports that were not scheduled in RT for the hour
- RT IOG will be settled under new charge type 1927 – Real-Time Intertie Offer Guarantee
- An example of the IOG offset process is provided in MM5.5, Appendix D

Hourly Settlement Amounts: Real-Time Intertie Failure Charges

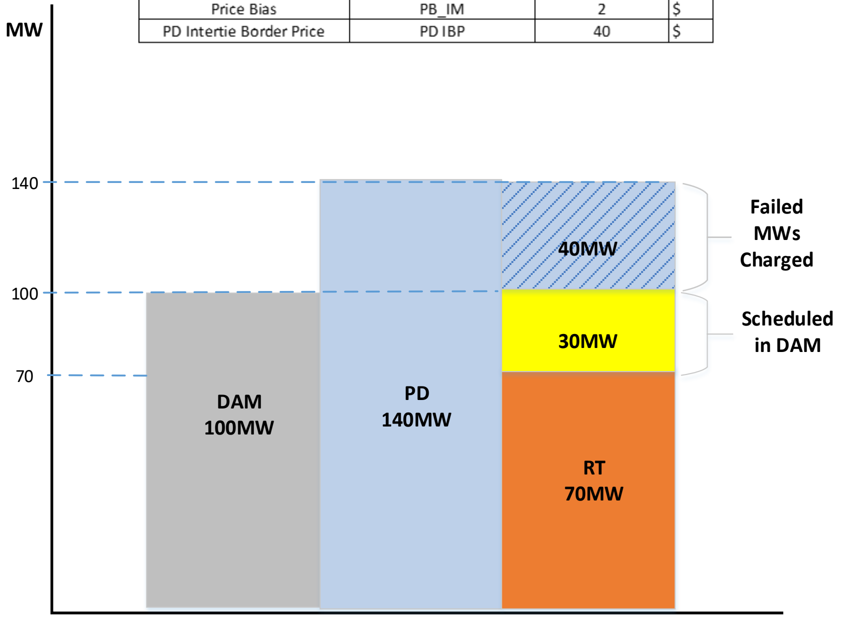
Background: Real-Time Intertie Failure Charge

- Discourages market participant from failing transactions by applying a financial charge
- Only MWs that are incremental to DAM schedules are eligible for a failure charge
- Is applicable to import and export transactions that failed within their control
- Will be settled under the existing charges CT 135 and CT 136

Import Failure Charge

Scenario 1 : Import was scheduled in DAM and failed to deliver scheduled MWs in RT

Input Data			
Name	Variable	Quantity	Units
RT Intertie Border Price	RT IBP	50	$
Price Bias	PB_IM	2	$
PD Intertie Border Price	PD IBP	40	$



1. Determine the failure quantity

Failed Qty =Max(Max(PDq – DAMq),0) – Max(RTq - DAMq,0),0)

Failed Qty = (Max(Max(140 – 100,0) – Max(70 -100,0),0)

= 40 MW

2. Calculate the price impact

PD impact = Max((RT_IBP + PB – PD_IBP) x failed qty,0)

= Max((50 + 2 – 40) x 40MW

= $480

RT impact =Max(0, RT_IBP x failed Qty)

= Max(0, 50 x 40 MW)

= $2000

RT_IMFC = Min(PD impact, RT impact,0)

= Min($480, $2000) = **$480**

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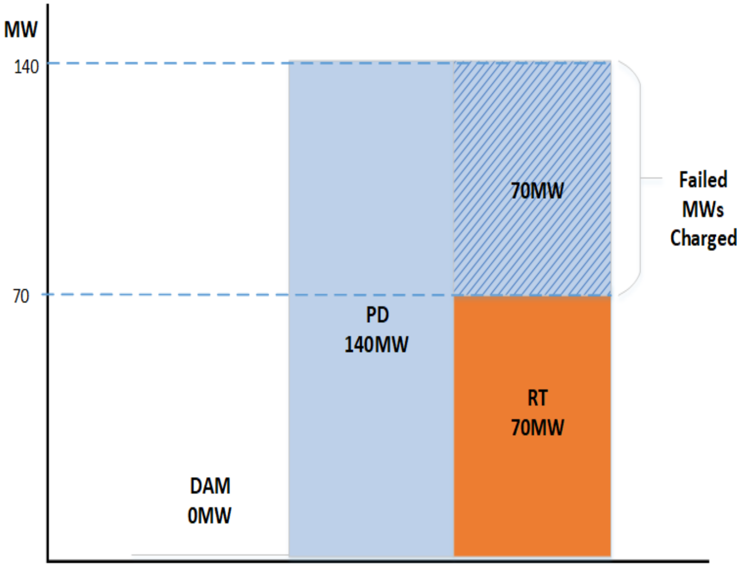
Export Failure charge

Scenario 2 : Export failed to deliver scheduled MWs in RT and does not have a DAM schedule

Input Data			
Name	Variable	Quantity	Units
RT Intertie Border Price	RT IBP	40	$
Price Bias	PB_EX	1	$
PD Intertie Border Price	PD IBP	50	$



1. Determine the failure quantity

Failed Qty =Max(Max(PDq – DAMq),0) – Max(RTq - DAMq,0),0)

Failed Qty = (Max(Max(140 – 0,0) – Max(70 -0,0),0)

= 70 MW

2. Calculate the price impact

RT impact = Max((PD_IBP + PB – RT_IBP) x failed qty,0)

= Max(($50 + 1 – $40) x 70MW

= $770

PD impact =Max(0, PD_IBP x failed Qty)

= Max(0, $50 x 70 MW)

= $3500

RT_IMFC = Min(PD impact, RT impact,0)

= Min($770, $3500) = **$630**

Hourly Settlement Amounts: Transmission Rights

Transmission Rights

Current Market

- Settled at the real-time intertie congestion price (ICP) which excludes NISL, calculated as the difference between IZP and MCP
- Transmission rights (TRSC) will be calculated as:
  - TRSC = Max[0, QTR x ($EMP^{j,i}$ – $EMP^{i,j}$)]
  - Where i,j represents the injection and withdrawal TR zones
- TRs are settled in real time

Future Market

- ICP = DAM_PEC + NISL
- Settled at day-ahead external congestion price (DAM_PEC), as
- TRSC will be calculated as:
  - TRSC = QTR x DAM_PEC for injection TR zone (export congested)
  - TRSC = -1 x QTR x DAM_PEC for withdrawal TR zone (import congested)
- TRs are settled in the DAM timeframe

Transmission Rights – Example

Scenario: An exporter owns a TR to hedge export congestion

DAM_QSW (MW)	DAM_LMP	DAM_PEC	TR owned for export congestion
100	$45	$15	100

DAM energy settlement = DAM_QSW x DAM_LMP

= 100MW x $45 = $4,500

TR settlement = DAM_PEC x export TRs owned

= $15 x 100 MW = $1,500

DAM External Congestion Collection and Disbursement

- DAM external congestion cost residuals will be collected into the Transmission Rights Clearing Account (TRCA)
- Surplus residuals remaining from settling the TR market (i.e. DAM external congestion residuals collected plus TR auction revenues less TR market payouts) will continue to be disbursed from the TRCA to loads and exporters according to existing market rules

Hourly Settlement Amounts:
Hourly Uplifts

Hourly Uplifts

- Similar to the current market, hourly uplifts are collected or disbursed to loads and exports that consume in the real-time market on a pro-rata basis
- There are 6 new hourly uplifts:
  - Real-time make-whole payment uplift (CT 1950)
  - Real-time Intertie offer guarantee uplift (CT 1977)
  - DAM Balancing credit uplift (CT 1865)
  - DAM Reference level settlement charge uplift (CT1980)
  - RT Reference level settlement charge uplift (CT 1981)
  - Generation failure charge – market price (CT 1970)

Market Rule Chapter 9 Section Summary: Non-Hourly Settlement Amounts

Non-Hourly Settlement Amounts:
Day-Ahead Market Generator Offer Guarantee

Background : Day-Ahead Market Generator Offer Guarantee (DAM_GOG)

- Provide compensation to GOG-eligible resources for any loss they incur relative to costs implied by their offers for the period in which their resource is committed by the day-ahead market calculation engine
- DAM_GOG will be calculated over the DAM commitment period for which a GOG-eligible resource received a contiguous DAM financial binding schedule within a single dispatch day
- The commitment period will consist of three possible variants each of which determines the components that will be included in the calculation

Day-Ahead Market Generator Cost Guarantee – Key Changes

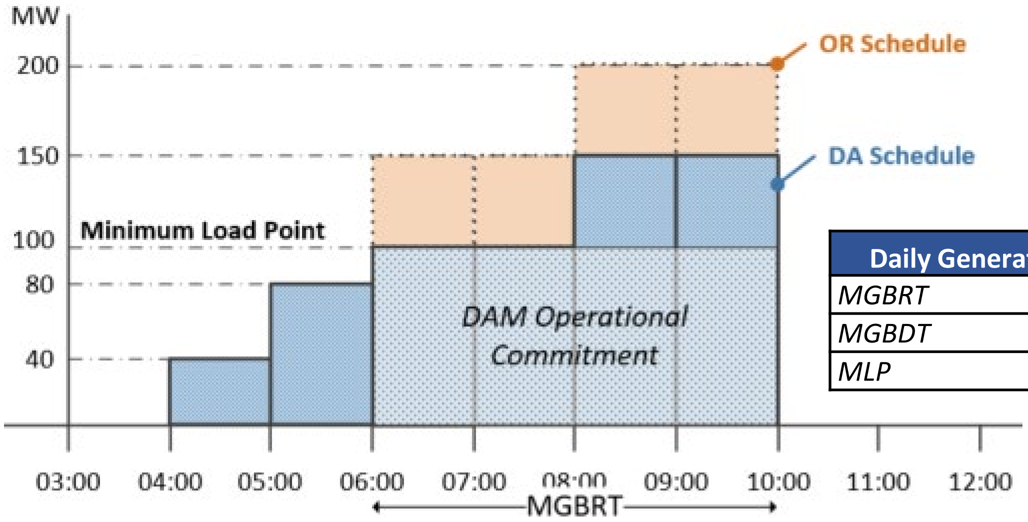
- The following changes/clarification have been made to the DAM_GOG since the detailed design:

- Adding a new ineligibility provision to limit DAM_GOG for the period that the resource is scheduled at the beginning of the dispatch day due to ramp rate limitation for the purpose of ramping down to offline (s 4.4.2.2)

- Clarify the definition of variant 1, 2 and 3

DAM_GOG – Scenario 1

- Resource is scheduled in the day-ahead market from HE5 to HE10 for energy and operating reserve with a day-ahead operational commitment from HE7 to HE10
- No commitments or schedules in the preceding or succeeding hours



Daily Generation Data	
MGBRT	4 hrs
MGBDT	2 hrs
MLP	100 MW

DAM Price and Schedule		
HE	**DA_LMP ($)**	**DA_QSI (MW)**
5	40	40
6	40	80
7	40	100
8	40	100
9	40	150
10	40	150

DAM OR 10S Price and Schedule		
HE	***DAM_PROR***	***DAM_QSOR***
5		
6		
7	2	50
8	2	50
9	2	50
10	2	50

DAM_GOG – Scenario 1

- The energy and OR offers are the same for all of the scheduled hours

DAM Energy Offers (DAM_BE)		
PQ #	Price ($/MWh)	Quantity (MW)
1	35	0
2	35	100
3	40	200
4	50	300

Start-Up Offer $ (DAM_BE_SU)
10,000

SNL Offer $ (DAM_BE_SNL)
800

DAM OR 10S Offer(DAM_BOR)		
PQ #	Price ($/MWh)	Quantity (MW)
1	1.5	0
2	1.5	50
3	3	100

- Resource injects in real-time and achieves MLP at the first interval of the day-ahead operational commitment

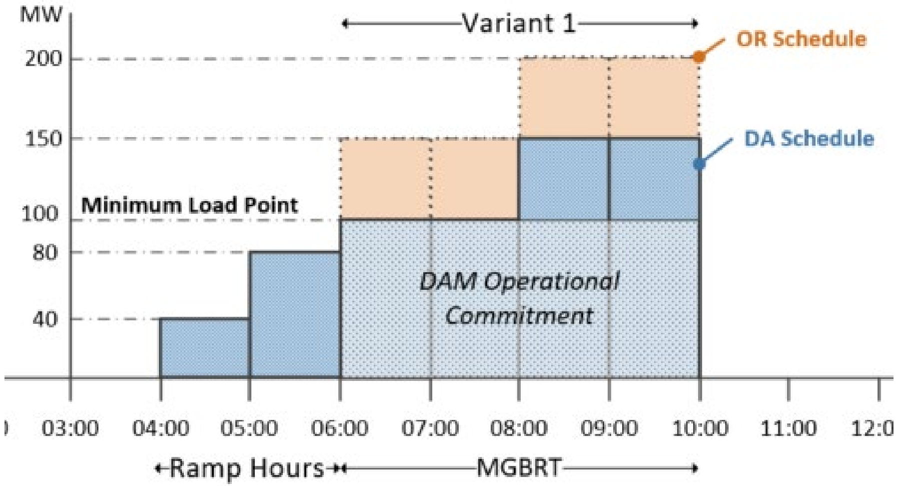
RT Hourly Schedule and Injection		
HE	RT_QSI (MW)	AQEI (MW)
5	40	40
6	80	80
7	100	100
8	100	100
9	150	150
10	150	150

**Assumption: resource is scheduled and injecting at the day-ahead position in all of the scheduled hours*

DAM_GOG Calculation – Scenario 1

Step 1: Determine the commitment period, variant number and ramp hours for GOG calculation

HE	Period Definition	Variant #
5	Ramp-up period	
6	Ramp-up period	
7	Day-ahead commitment period	1
8	Day-ahead commitment period	1
9	Day-ahead commitment period	1
10	Day-ahead commitment period	1



DAM_GOG for Variant 1 = Max(0, COMP1 + COMP2 + COMP4 - COMP5)

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DAM_GOG Calculation – Scenario 1

Step 2: Calculation of DAM_GOG Component 1

DAM_GOG_COMP1 = - OP(DAM Energy) + SNL Cost – Ramp Revenue

- 1 x OP(DAM Energy)		
HE	**-1 x OP(DAM_LMP,DAM_QSI,DAM_BE)**	**Result**
5		
6		
7	-1 x (40$/MWh x 100MW - 35$/MWh x 100MW) =	**-500**
8	-1 x (40$/MWh x 100MW - 35$/MWh x 100MW) =	**-500**
9	-1 x (40$/MWh x 150MW - 40$/MWh x 50MW - 35$/MWh x 100MW) =	**-500**
10	-1 x (40$/MWh x 150MW - 40$/MWh x 50MW - 35$/MWh x 100MW) =	**-500**

- *The operating profit for energy will be calculated for each hour of the commitment period from HE7 to HE10, excluding the ramp hours*

DAM_GOG Calculation – Scenario 1

Step 2: Calculation of DAM_GOG Component 1

DAM_GOG_COMP1 = - OP(DAM Energy) + SNL Cost – Ramp Revenue

SNL Cost			
HE	***N - # of Inj Int***	***DAM_BE_SNL x N/12***	**Result**
5			
6			
7	12	800 x 12/12 =	**800**
8	12	800 x 12/12 =	**800**
9	12	800 x 12/12 =	**800**
10	12	800 x 12/12 =	**800**

- *The speed no-load will be calculated for each hour of the commitment period starting from HE7 to HE10*
- *N is the number of metering intervals in the settlement hour that the resource was synchronized and injecting energy into the grid*
- *As resource is injecting for all four hours of the commitment period, **N=12** for all four hours*

DAM_GOG Calculation – Scenario 1

Step 2: Calculation of DAM_GOG Component 1

DAM_GOG_COMP1 = - OP(DAM Energy) + SNL Cost – Ramp Revenue

COMP1 = - OP(DAM Energy) + SNL Cost – Ramp Revenue				
HE	***-OP (DAM Energy)***	***SNL Cost***	**-Ramp Revenue**	**COMP1**
5			-1,600	**-1,600**
6			-3,200	**-3,200**
7	-500	800		**300**
8	-500	800		**300**
9	-500	800		**300**
10	-500	800		**300**

- Ramp Revenue		
HE	**- DAM_LMP x DAM_QSI**	**Result**
5	- 40$ x 40 MW =	**-1,600**
6	- 40$ x 80 MW =	**-3,200**
7		
8		
9		
10		

DAM_GOG Calculation – Scenario 1

Step 3: Calculation of DAM_GOG Component 2

DAM_GOG_COMP2 = -1 x OP(DAM OR)

COMP2 = -1 x OP(DAM_QSOR)		
HE	**-1 x OP(DAM_PROR,DAM_QSOR,DAM_BOR)**	**COMP2**
5		
6		
7	-1 x (2$/MWh x 50MW - 1.5$/MWh x 50MW) =	**-25**
8	-1 x (2$/MWh x 50MW - 1.5$/MWh x 50MW) =	**-25**
9	-1 x (2$/MWh x 50MW - 1.5$/MWh x 50MW) =	**-25**
10	-1 x (2$/MWh x 50MW - 1.5$/MWh x 50MW) =	**-25**

DAM_GOG Calculation – Scenario 1

Step 4: Calculation of DAM_GOG Component 4 (Start-up)

COMP4 = DAM_BE_SU		
HE	***DAM_BE_SU***	**COMP4**
5		
6		
7	10,000	**10,000**
8		
9		
10		

- *The start-up offer associated with the **first hour (HE7)** of the commitment period is considered in the GOG calculation*
- *As the resource achieves MLP on time at the first interval of the commitment period, the **full** start-up offer is included in the calculation*

DAM_GOG Calculation – Scenario 1

Step 5: Calculation of DAM GOG

DAM_GOG = Max(0, COMP1 + COMP2 + COMP4 - COMP5)					
HE	**COMP1**	**COMP2**	**COMP4**	**- COMP5**	**Total**
5	-1,600				**-1,600**
6	-3,200				**-3,200**
7	300	-25	10,000		**10,275**
8	300	-25			**275**
9	300	-25			**275**
10	300	-25			**275**
Total	**-3,600**	**-100**	**10,000**	**0**	**6,300**
DAM_GOG = Max(0,6300) = $6,300					

- *Resource is scheduled economically in all hours of the commitment period, therefore no DAM_MWP is generated:* ***COMP5 = 0***

DAM_GOG Calculation – Scenario 1

The DAM_GOG (**$6,300**) is a positive value; hence the following settlement amounts will appear on the settlement statement:

Settlement Amounts on Settlement Statement							
		HE 5	HE 6	HE 7	HE 8	HE 9	HE 10
1804	Day-Ahead Market generator Offer Gurantee - Energy	-$1,600	-$3,200	$300	$300	$300	$300
1805	Day-Ahead Market generator Offer Gurantee - Operating Reserve			-$25	-$25	-$25	-$25
1807	Day-Ahead Market generator Offer Gurantee - Start Up			$10,000			

Non-Hourly Settlement Amounts:
Real-Time Generator Offer Guarantee

Background: Real-Time Generator Offer Guarantee (RT_GOG)

- Provide compensation to GOG-eligible non quick-start resource 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 be calculated over the RT commitment period for which GOG eligible resource received a contiguous PD operational commitment within a single dispatch day
- The commitment period will consist of three possible variants each of which determines the components that will be included in the calculation

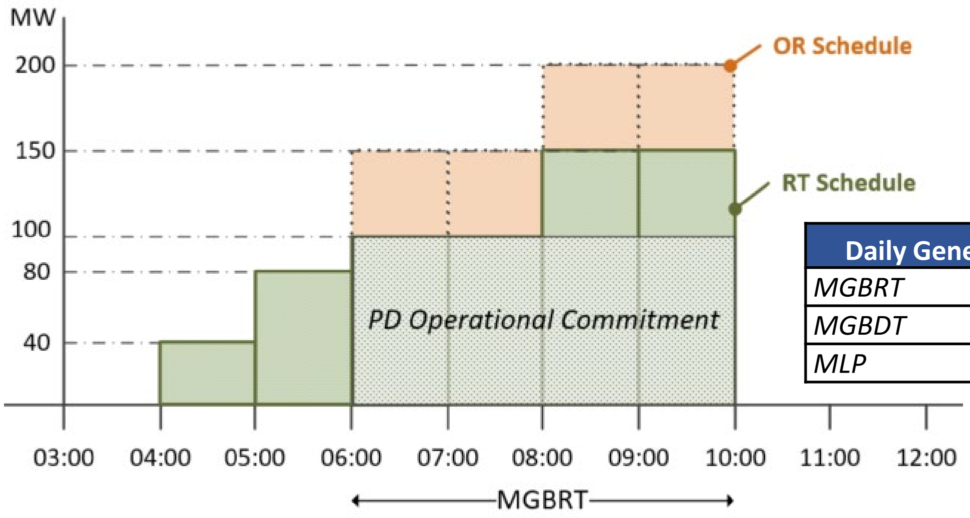
Real-Time Generator Offer Guarantee – Key Changes

The following changes/clarification have been made to the RT_GOG since the detailed design:

- Limiting the RT_GOG commitment period to a time span within the dispatch day. If resource is injecting across midnight, the event will be split into two commitment periods and calculated separately (MM 5.5 s 2.11)
- Adding a new ineligibility provision to limit RT_GOG for the period that the resource has a
  - binding combined cycle physical unit constraint (s 4.5.6 d) ; or
  - constraint on request from the market participant, to prevent endangering the safety of any person, equipment damage, or violation of any applicable law (s 4.5.2 ii & iii)
- Clarify real-time reliability commitment period and it's application in RT_GOG components (s.4.5.1)

RT_GOG – Scenario 1

- Resource is committed by the pre-dispatch engine with an operational commitment from HE7 to HE10. It is scheduled in real-time for both energy and operating reserve
- No commitments or schedules in the preceding or succeeding hours



Daily Generation Data	
MGBRT	4 hrs
MGBDT	2 hrs
MLP	100 MW

RT Price and Schedule		
HE	**RT_LMP ($)**	**RT_QSI (MW)**
5	40	40
6	40	80
7	40	100
8	40	100
9	40	150
10	40	150

RT OR 10S Price and Schedule		
HE	***RT_PROR***	***RT_QSOR***
5		
6		
7	2	50
8	2	50
9	2	50
10	2	50

RT_GOG – Scenario 1

- The energy and OR offers are the same for all of the scheduled hours
- Resource injects in real time and achieves MLP at the first interval of the pre-dispatch operational commitment

RT Energy Offers (BE)		
PQ #	Price ($/MWh)	Quantity (MW)
1	35	0
2	35	100
3	40	200
4	50	300

Start-Up Offer $ (PD_BE_SU)
10,000

SNL Offer $ (PD_BE_SNL)
800

RT OR 10S Offer(BOR)		
PQ #	Price ($/MWh)	Quantity (MW)
1	1.5	0
2	1.5	50
3	3	100

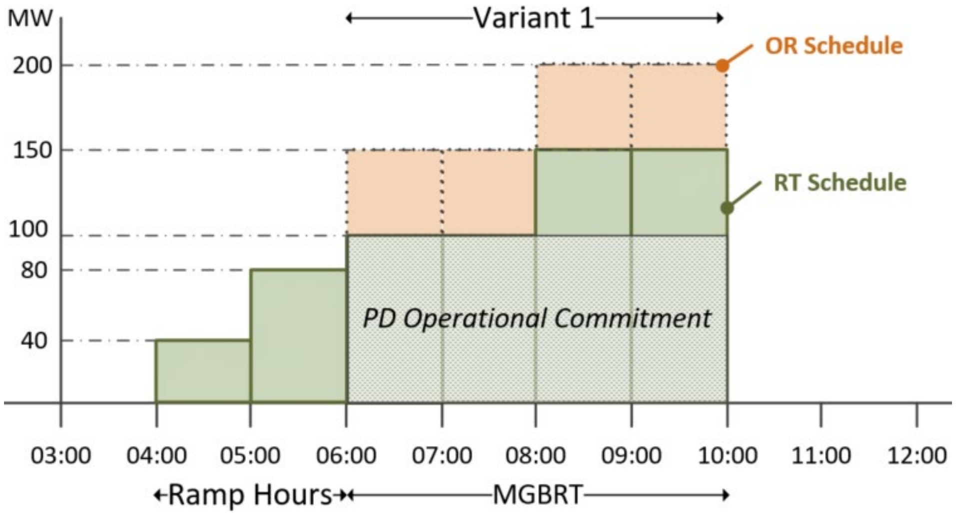
RT Hourly Schedule and Injection		
HE	RT_QSI (MW)	AQEI (MW)
5	40	40
6	80	80
7	100	100
8	100	100
9	150	150
10	150	150

**Assumption: resource is injecting at the real-time scheduled position*

RT_GOG Calculation – Scenario 1

Step 1: Determine the commitment period, variant number and ramp hours for GOG calculation

HE	Period Definition	Variant #
5	Ramp-up period	
6	Ramp-up period	
7	Real-time commitment period	1
8	Real-time commitment period	1
9	Real-time commitment period	1
10	Real-time commitment period	1



DAM_GOG for Variant 1 = Max(0, COMP1 + COMP2 + COMP4 - COMP5)

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RT_GOG Calculation – Scenario 1

Step 2: Calculation of RT_GOG Component 1

RT_GOG_COMP1 = - OP(RT Energy) + SNL Cost – Ramp Revenue

- 1 x OP(RT Energy)		
HE	**-1 x Max(OP(RT_LMP,RT_QSI,BE), OP(RT_LMP,AQEI,BE))*** **	**Result**
5		
6		
7	-1 x (40$/MWh x 100MW - 35$/MWh x 100MW) =	**-500**
8	-1 x (40$/MWh x 100MW - 35$/MWh x 100MW) =	**-500**
9	-1 x (40$/MWh x 150MW - 40$/MWh x 50MW - 35$/MWh x 100MW) =	**-500**
10	-1 x (40$/MWh x 150MW - 40$/MWh x 50MW - 35$/MWh x 100MW) =	**-500**

****As RT_QSI=AQEI, the operating profit calculation is the same for the two quantities****

- *The operating profit for energy will be calculated for each hour of the commitment period from HE7 to HE10, excluding the ramp hours*

RT_GOG Calculation – Scenario 1

Step 2: Calculation of RT_GOG Component 1

RT_GOG_COMP1 = - OP(RT Energy) + SNL Cost – Ramp Revenue

SNL Cost			
HE	***N - # of Inj Int***	***PD_BE_SNL x N/12***	**Result**
5			
6			
7	12	800 x 12/12 =	**800**
8	12	800 x 12/12 =	**800**
9	12	800 x 12/12 =	**800**
10	12	800 x 12/12 =	**800**

- *The speed-no-load will be calculated for each hour of the commitment period starting from HE7 to HE10*
- *N is the number of metering intervals in settlement hour that the resource was synchronized and injecting energy into the grid*
- *As resource is injecting for all four hours of the commitment period, **N=12** for all four hours*

RT_GOG Calculation – Scenario 1

Step 2: Calculation of RT_GOG Component 1

RT_GOG_COMP1 = - OP(RT Energy) + SNL Cost – Ramp Revenue

COMP1 = - OP(RT Energy) + SNL Cost – Ramp Revenue				
HE	***-OP (RT Energy)***	***SNL Cost***	**-Ramp Revenue**	**COMP1**
5			-1,600	**-1,600**
6			-3,200	**-3,200**
7	-500	800		**300**
8	-500	800		**300**
9	-500	800		**300**
10	-500	800		**300**

- Ramp Revenue		
HE	**- RT_LMP x AQEI**	**Result**
5	- 40$ x 40 MW =	**-1,600**
6	- 40$ x 80 MW =	**-3,200**
7		
8		
9		
10		

RT_GOG Calculation – Scenario 1

Step 3: Calculation of RT_GOG Component 2

RT_GOG_COMP2 = -1 x OP(RT OR)

COMP2 = -1 x OP(RT_QSOR)		
HE	**-1 x OP(RT_PROR,RT_QSOR,BOR)**	**COMP2**
5		
6		
7	-1 x (2$/MWh x 50MW - 1.5$/MWh x 50MW) =	**-25**
8	-1 x (2$/MWh x 50MW - 1.5$/MWh x 50MW) =	**-25**
9	-1 x (2$/MWh x 50MW - 1.5$/MWh x 50MW) =	**-25**
10	-1 x (2$/MWh x 50MW - 1.5$/MWh x 50MW) =	**-25**

RT_GOG Calculation – Scenario 1

Step 4: Calculation of RT_GOG Component 4

COMP4 = PD_BE_SU		
HE	***PD_BE_SU***	**COMP4**
5		
6		
7	10,000	**10,000**
8		
9		
10		

- *The start-up offer associated with the **first hour (HE7)** of the commitment period is considered in the GOG calculation*
- *As the resource achieves MLP on time at the first interval of the commitment period, the **full** start-up offer is included in the calculation*

RT_GOG Calculation – Scenario 1

Step 5: Calculation of RT_GOG

RT_GOG = Max(0, COMP1 + COMP2 + COMP4 - COMP5)					
HE	**COMP1**	**COMP2**	**COMP4**	**- COMP5**	**Total**
5	-1,600				**-1,600**
6	-3,200				**-3,200**
7	300	-25	10,000		**10,275**
8	300	-25			**275**
9	300	-25			**275**
10	300	-25			**275**
Total	**-3,600**	**-100**	**10,000**	**0**	**6,300**
RT_GOG = Max(0,6300) = $6,300					

- *Resource is scheduled economically in all hours of the commitment period, therefore no DAM_MWP is generated:* ***COMP5 = 0***

RT_GOG Calculation – Scenario 1

The RT_GOG (**$6,300**) is a positive value; hence the following settlement amounts will appear on the settlement statement:

Settlement Amounts on Settlement Statement							
		HE 5	HE 6	HE 7	HE 8	HE 9	HE 10
1910	Real Time Generator Offer Gurantee - Energy	-$1,600	-$3,200	$300	$300	$300	$300
1911	Real Time Generator Offer Gurantee - Operating Reserve			-$25	-$25	-$25	-$25
1913	Real Time Generator Offer Gurantee - Start Up			$10,000			

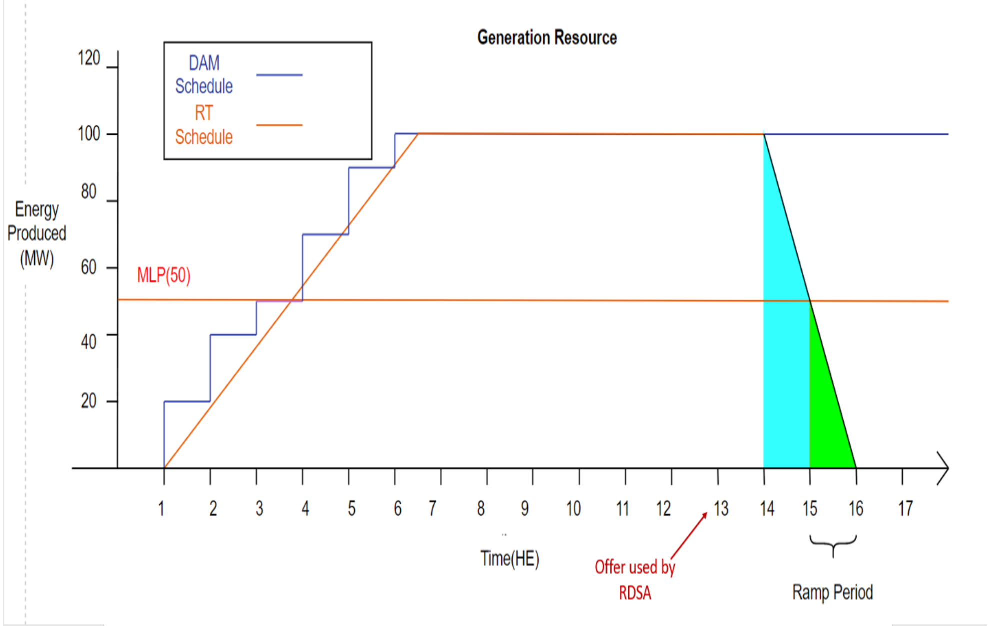
Non-Hourly Settlement Amounts:
Real-Time Ramp Down Settlement Amount

Background: Real-Time Ramp Down Settlement Amounts (RDSA)

- RDSA compensates a GOG-eligible resource when revenue below MLP does not cover its cost to operate
- RDSA will be adjusted for any hours for which the resource has a DAM schedule while ramping down
- Similar to the current market, the offer price used in the calculation:
  - will be based on the hour prior to resource ramping down
  - will consider if the resource is ramp rate limited and deviating from dispatch instructions
  - ramp down factor is 1.3

Ramp Down Settlement Amount – Scenario 1

Scenario 1: Generator starts ramping down above MLP to come offline



DAM Energy Offers (DAM_BE)		
PQ#	Price($/MWh)	Quantity (MW)
1	50	0
2	50	100

DAM_LMP	$40

RT Energy Offers (BE)		
PQ#	Price($/MWh)	Quantity (MW)
1	60	0
2	60	100

AQEI (MW)	30

RDSA for the ramp period is calculated as:

OP(DAM_LMP,AQEI,DAM_BE)		
Revenue	$40 x 30 =	$1200
Cost (offer x RDF)	($50 x 1.3) x 30 =	
		$1,950
Net	-1 x ($1200 - $1950 = $750	

OP(DAM_LMP,AQEI,BE)		
Revenue	$40 x 30 =	$1200
Cost (offer x RDF)	($60 x 1.3) x 30 =	
		$2,340
Net	-1 x ($1200 - $2340) = $1100	

$RT\_RDSA = -1 * OP(DAM\_LMP, AQEI, BE) - \text{Max}(0, -1 * OP(DAM\_LMP, AQEI, DAM\_BE))$	
Compensation	$1100 - $750 = $350

RDSA of $350 will appear on settlement statement as CT 1917

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Non-Hourly Settlement Amounts: Internal Congestion and Loss Residuals

Background : Internal Congestion and Loss Residuals

- Internal congestion and loss residuals is the residual collected from the sales and purchase of energy by generators and loads in Ontario
- The amount paid for energy by loads does not always equal the amount paid to generators, due to locational pricing and the physical realities of the IESO-controlled grid (i.e. congestion and line losses)
- Internal congestion and loss residuals will be disbursed or collected from all loads (i.e. PRLs, dispatchable and non-dispatchable loads) on a monthly basis

Internal Congestion and Loss Residuals

- The formula to calculate total congestion rent and loss residual collected (CRLR) was revised to exclude external congestion and congestion collected from NISL in day-ahead and real-time (s 4.7.2)

Congestion Rent and Loss Residual (CRLR) = Term1 + Term2 + Term3 + Term4 - Term 5 –Term 6

Term	Collection from:
Term 1	Congestion rent and marginal loss accrued in the DAM and the RTM to settle all generators, dispatchable loads and price responsive loads
Term 2	+ congestion rent and marginal loss accrued in the DAM and the RTM 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	- DAM and RT external congestion collected on interties when interties are either import-congested or export-congested
Term 6	- DAM and RT NISL congestion collected on interties

Internal Congestion and Loss Residual

Example: Assume a CRLR of $7,000 was calculated and will be disbursed to loads

Participant	Participant's Monthly RTM Consumption (MWh)	Monthly Ratio (Participant's Monthly RTM Consumption /Total RTM Consumption)	CRLR	Internal congestion & Loss distribution (Monthly Ratio x CRLR)
Load 1	4,000	4,000/24,000 = 17%	$7,000	$1,190
Load 2	8,000	8,000/24,000 = 33%		$2,310
Load 3	12,000	12,000/24,000 = 50%		$3,500

- A load will receive a portion of the CRLR if it consumes in real time

Non-Hourly Settlement Amounts:
Real-Time External Congestion, Real-Time and Day-Ahead Market NISL Residual

Background: Real-Time External Congestion and NISL

- Real-time external congestion, day-ahead and real-time NISL residuals is the residual remaining from settling export and import transactions
- Charges to exporters do not equal payments to importers at the interties when scheduling limits such as import limits, export limits and NISL bind (i.e. their cost components have a non-zero value)
- More information on real-time external congestion and NISL disbursement is available in the presentation "External Congestion and NISL Congestion Cost Residual Collection and Disbursement" on February 22, 2022
- The market rules codify the design (s 4.8) presented on February 22, 2022

Real-Time External Congestion

- Real-time external congestion residual (“RT_ECR”) will be calculated as:

$$RT\_ECR = \sum_{K,H}^{I,T} \left(\left(SQEW_{k,h}^{i,t} - SQEI_{k,h}^{i,t} \right) - \left(DAM\_QSW_{k,h}^{i} - DAM\_QSI_{k,h}^{i} \right) \right) \times RT\_PEC_{h}^{i,t} / 12$$

Where $RT\_PEC_{h}^{i,t}$ is the *real-time market* price of external congestion component (in $/MWh) of the *locational marginal price* at *intertie metering point* ‘i’ in *metering interval* ‘t’ of *settlement hour* ‘h’.

- RT_ECR will be disbursed or collected on a **monthly** basis to loads and exports based on their proportion of transmission service charges paid over the past month
- This distribution methodology is similar to that used to disburse TRCA in the current market

Day-Ahead Market NISL Residual

- Day-ahead market NISL residual (“DAM_NISLR”) will be calculated as:

$$DAM\_NISLR = \sum_{K,H}^{I} [(DAM\_QSW_{k,h}^{i} - DAM\_QSI_{k,h}^{i})\ x\ DAM\_PNISL_{h}^{i}]$$

Where $DAM\_PNISL_{h}^{i}$ is the net interchange scheduling limit component (in $/MWh) of the *locational marginal price* at *intertie metering point* ‘i' in *settlement hour* ‘h’

- DAM_NISLR will be disbursed or collected on a **daily** basis to loads and exports based on their proportionate share of daily metered consumption in the real time

Real-Time NISL Residual

- Real-time NISL residual ("RT_NISLR") will be calculated as:

$$RT\_NISLR_h = \sum_K^{I,T} \left(\left(SQEW_{k,h}^{i,t} - SQEI_{k,h}^{i,t} \right) - \left(DAM\_QSW_{k,h}^{i} - DAM\_QSI_{k,h}^{i} \right) \right) \times RT\_PNISL_h^{i,t} / 12$$

Where $RT\_PNISL_h^{i,t}$ the *real-time market* price of the net interchange scheduling limit component (in $/MWh) of the *locational marginal price* at *intertie metering point* 'i' in *metering interval* 't' of *settlement hour* 'h'

- RT_NISLR will be disbursed or collected on a **hourly** basis to loads and exports based proportionate share of hourly metered consumption in the real time

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Non-Hourly Settlement Amounts:
Generator Failure Charge

Background: Generator Failure Charge (GFC)

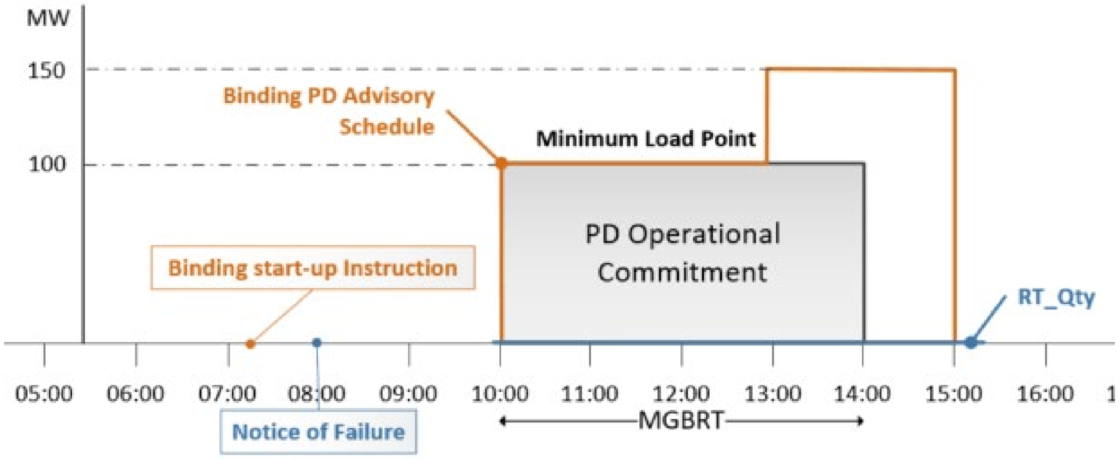
- The calculation of the GFC will occur when a GOG-eligible resource fails to deliver energy as committed by the PD calculation engine
- The failure charge is intended to reduce the risk of system reliability events due to failed commitments and to improve efficiency
- GFC will be broken into two components:
  - Market Price Component (GFC_MPC) settled as CT 1920 – Generator Failure Charge – Market Price Component
  - Generator Cost Component (GFC_GCC) settled as CT 1921 - Generator Failure Charge – Guarantee Cost Component

Generator Failure Charge - Key Changes

- Added new eligibility rules when a resource is dispatched on request from the market participant, to prevent endangering the safety of any person, equipment damage, or violation of any applicable law (s 4.10.3c)

GFC – Scenario 1

- The pre-dispatch calculation engine issues a binding start-up instruction at ~7:15 for a commitment from HE11 to HE14
- Resource has a binding PD advisory schedule (issued at 7:15) from HE11 to HE15
- Resource informs the IESO 2 hours before the commitment that it cannot meet the commitment



RT Price and Schedule		
HE	**RT_LMP ($)**	**RT_QSI (MW)**
11	50	0
12	50	0
13	50	0
14	50	0
15	50	0

Daily Generation Data	
MGBRT	4 hrs
MGBDT	2 hrs
MLP	100 MW

GFC – Scenario 1

- The energy offers are the same for all of the scheduled hours
- The binding PD advisory schedule at 7:15 schedules the resource from HE11 to HE15

PD Energy Offers (BE)		
PQ #	**Price ($/MWh)**	**Quantity (MW)**
1	35	0
2	35	100
3	40	200
4	50	300

Start-Up Offer $ (PD_BE_SU)
5,000

SNL Offer $ (PD_BE_SNL)
900

PD Advisory Price and Schedule		
HE	***PD_LMP@BSUI***	***PD_QSI@BSUI***
11	36	100
12	36	100
13	36	100
14	42	150
15	42	150

*BSUI – Binding start-up instruction

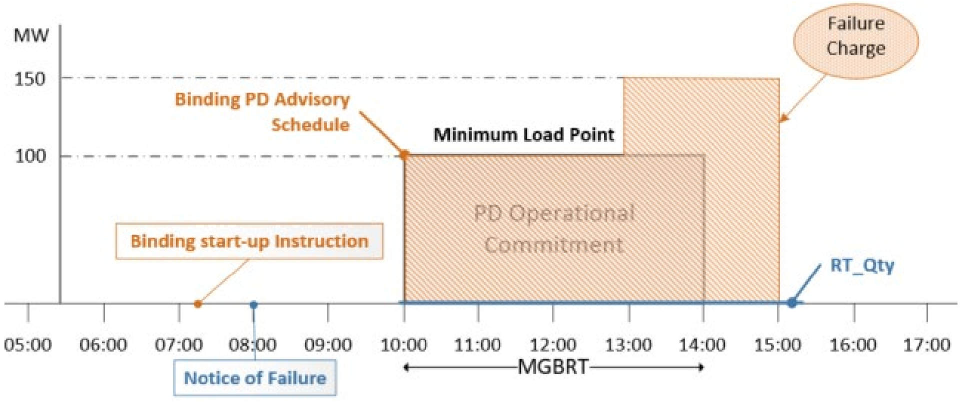
GFC Calculation – Scenario 1

Determine the failure period for GFC calculation

<u>Failure Event:</u> Failing to inject into the IESO-controlled grid to meet a pre-dispatch operational commitment

<u>Failure Period:</u> All metering intervals of the GOG-eligible resource's binding pre-dispatch advisory schedule issued at the time of start-up notice

HE	Period Definition
11	Failure hour (All intervals)
12	Failure hour (All intervals)
13	Failure hour (All intervals)
14	Failure hour (All intervals)
15	Failure hour (All intervals)



GFC_MPC Calculation – Scenario 1

Resource provides less than four hours of advance notice of the generator failure, the GFC_MPC is calculated as:

GFC_MPC = -1 x (RT_LMP - PD_LMP) x (PD_QSI - AQEI)

GFC_MPC		
HE	**-1 x (RT_LMP - PD_LMP) x (PD_QSI - AQEI)**	**GFC_MPC**
11	-1 x (50 - 36) x (100 - 0) =	**-1400**
12	-1 x (50 - 36) x (100 - 0) =	**-1400**
13	-1 x (50 - 36) x (100 - 0) =	**-1400**
14	-1 x (50 - 42) x (150 - 0) =	**-1200**
15	-1 x (50 - 42) x (150 - 0) =	**-1200**

Result:
The hourly GFC_MPC amounts will appear on the settlement statement as charge type 1920

GFC_GCC Calculation – Scenario 1

Step 1: Determine the prorating factor for Start-up Offer - PD_SU_Ratio

PD_SU_Ratio = Min(1,MLP_INJ/MGBRT)

- *MLP_INJ is the number of metering intervals within the MGBRT period that the resource is injecting below MLP*

    MLP_INJ = 12 intervals x 4 hours = 48

- *MGBRT is the number of metering intervals of the minimum generation block run-time*

    MGBRT = 12 intervals x 4 hours = 48

PD_SU_Ratio = Min(1,MLP_INJ/MGBRT) = Min(1,48/48) = 1

GFC_GCC Calculation – Scenario 1

Step 2: Determine the GCC for each hour

GFC_GCC = -1 x (PD_SU_Ratio x SU_INCR+ SNL - OP(PD_QSI)

PD_SU_Ratio x SU_INCR				
HE	***PD_SU_Ratio***	***SU_INCR = PD_BE_SU***	**PD_SU_Ratio x SU_INCR**	***Result***
11	1	5000	= 1 x 5000 =	**5000**
12				
13				
14				
15				

- *The start-up offer associated with the **first hour (HE11)** of the commitment period is considered in the GFC_GCC calculation*
- *The pre-dispatch operational commitment is a stand-alone commitment without any* commitments or schedules in the preceding or succeeding hours, therefore ***SU_INCR = PD_BE_SU***

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GFC_GCC Calculation – Scenario 1

Step 2: Determine the GCC for each hour

GFC_GCC = -1 x (PD_SU_Ratio x SU_INCR+ SNL - OP(PD_QSI)

SNL Cost			
HE	***N - # of Inj Int***	***PD_BE_SNL x N/12***	**Result**
11	12	900 x 12/12 =	**900**
12	12	900 x 12/12 =	**900**
13	12	900 x 12/12 =	**900**
14	12	900 x 12/12 =	**900**
15	12	900 x 12/12 =	**900**

- *The speed-no-load will be calculated for each hour of the failure period from HE11 to HE15*
- *N is the number of metering intervals in the settlement hour that the resource is within the failure period*
- *As resource failed all hours of the failure period,* ***N=12*** *for all five hours*

GFC_GCC Calculation – Scenario 1

Step 2: Determine the GCC for each hour

GFC_GCC = -1 x (PD_SU_Ratio x SU_INCR+ SNL - OP(PD_QSI)

- 1 x OP(PD_QSI)		
HE	**-1 x OP(PD_LMP,PD_QSI,PD_BE)**	**Result**
11	-1x(36$/MWh x 100MW - 35$/MWh x 100MW) =	**-100**
12	-1x(36$/MWh x 100MW - 35$/MWh x 100MW) =	**-100**
13	-1x(36$/MWh x 100MW - 35$/MWh x 100MW) =	**-100**
14	-1x(42$/MWh x 150MW - 40$/MWh x 50MW - 35$/MWh x 100MW) =	**-800**
15	-1x(42$/MWh x 150MW - 40$/MWh x 50MW - 35$/MWh x 100MW) =	**-800**

GFC_GCC Calculation – Scenario 1

Step 2: Determine the GCC for each hour

GFC_GCC = -1 x (PD_SU_Ratio x SU_INCR+ SNL - OP(PD_QSI)

GFC_GCC = -1 x (PD_SU_Ratio x SU_INCR+ SNL - OP(PD_QSI)				
HE	***PD_SU_Ratio x SU_INCR***	***SNL***	**-OP(PD_QSI)**	**Hourly GCC**
11	5000	900	-100	**-5,800**
12		900	-100	**-800**
13		900	-100	**-800**
14		900	-800	**-100**
15		900	-800	**-100**
			Total	**-7,600**

GFC_GCC Calculation – Scenario 1

Step 3: Determine the prorating factor for GCC - M1

M1 = 1 - ∑AQEI/∑PD_Qty

Total Quantity of Injection and PD Schedule		
HE	**AQEI**	**PD_QSI**
11	0	100
12	0	100
13	0	100
14	0	150
15	0	150
Total	**0**	**600**

- *The quantity of injection and quantity of PD schedule are summed over the entire failure period for the calculation of M1*

M1 = 1 - ∑AQEI/∑PD_Qty = 1 – 0/600 = 1

GCC = SUM of Hourly GCC x M1 = -$7600 x 1 = -$7600

Result:
The GCC is a negative value; hence the hourly GCC amounts which sum to -$7600 will appear on the settlement statement as charge type 1921

Non-Hourly Settlement Amounts: Fuel Cost Compensation

Background: Fuel Cost Compensation Credit

- Provides compensation for costs incurred in securing unused fuel when the IESO de-commits a resource prior to the start of the pre-dispatch operational commitment or de-synchronize the resource prior to it completing the pre-dispatch operational commitment
- Applicable to GOG-eligible resources only
- Allows GOG-eligible resources to recover the cost of fuel incurred to meet a day-ahead operational commitment or pre-dispatch operational commitment
- Only applicable to the procurement of fuel required to achieve the minimum loading point of the relevant operational commitment

Fuel Cost Compensation Credit – Submitting Claim

Participant action:

- Complete form in Online IESO
- Submit no later than one month after the trading day to which the claim applies
- Include all supporting documentation

IESO action:

- Assess if claim is valid:
  - Eligible cost(s) submitted per MR Ch.9 s.4.11.2
- If valid, credit will be applied to the participant's settlement statement for the last trading day of the month
- All claims are subject to audit by the IESO

Non-Hourly Settlement Amounts:
Non-Hourly Uplifts

Background: Non-Hourly Uplifts

- Similar to the current market, non-hourly uplifts are collected or disbursed to loads and exports that consume in the real-time market on a pro-rata basis
- There are 7 new non-hourly uplifts
  - Day Ahead Market Uplift (CT 1850)
  - Day Ahead Reliability Scheduling Uplift (CT 1851)*
  - Real-Time Generator Cost Guarantee (CT 1960)
  - Real-Time Ramp Down Settlement Amount Uplift (CT 1967)
  - Generator Failure Charge – Cost Guarantee Component Uplift (CT 1971)
  - Mitigation Amount for Physical Withholding Uplift (CT 1982)
  - Mitigation Amount for Intertie Economic Withholding Uplift (CT 1986)

Non-Hourly Settlement Amounts:
Non-Hourly Uplifts – DAM Reliability Scheduling Uplifts

Background: DAM Reliability Scheduling Uplifts (DRSU)

- The intent of DRSU is to uplift the cost associated with the scheduling of additional NQS and incremental MWs from boundary entities during Pass 2 – Reliability Scheduling and Commitment on a cost-causation basis
- DRSU is allocated first to virtual supply, then to loads and exports based on RT consumption
- Limited to costs associated with DAM_MWP and DAM GOG
- Settled as CT 1851 – Day-Ahead Reliability Scheduling Uplift

DAM Reliability Scheduling Uplifts – Key Changes

- Minor changes to the variable names and superscript to simplify the equations
- In addition, the equations have been updated to account for energy forecast for HDRs in DAM (s. 4.14.4.1c)
- Old Equation:

$$DAM\_NDL\_OF = \sum_{H,K}^{M} Max(DAM\_QSW_{k,h}^{m} - AQEW_{k,h}^{m,t}, 0)$$

- New Equation:

$$DAM\_NDL\_OF = \sum_{H,K}^{M} Max(DAM\_QSW_{k,h}^{m} + DAM\_HDR\_QSW_{k,h}^{m} - AQEW_{k,h}^{m,t}, 0)$$

DAM Reliability Scheduling Uplift – Scenario 1

Scenario 1: Additional energy was scheduled for an import in Pass 2 to meet demand

Import Offers in Pass 1 & Pass 2	
Price	**Quantity (MW)**
$50	0
$50	100

Import Schedule	Quantity (MW)
DAM_QSI^{p1}	30
DAM_QSI^{p2}	40
DAM_EOP	20

NDL	Quantity (MW)
DAM_QSW	10000
AQEW	9950

DAM LMP	$20

Assumption : no additional NQS resources were committed in pass 2

DAM_MWP = DAM_COMP1 + DAM_COMP2

There were no OR scheduled, hence DAM_MWP = DAM_COMP1

Note : p1 represents Pass 1
p2 represents Pass 2

DAM Reliability Scheduling Uplift – Scenario 1

Step 1: Determine DAM_MWP^{p1} in Pass 1

$DAM\_COMP1 = -1 \times [OP(DAM\_QSI^{p1}) - OP(DAM\_EOP)$

DAM_COMP1		
	$OP(DAM\_QSI^{p1})$	OP(DAM_EOP)
Revenue	30MW x $20 = $600	20MW x $20 = $400
Cost	30MW x $50 = $1500	20MW x $50 = $1000
Net	$600 -$1500 = -$900	$400 - $1000 = $ -$600
DAM_COMP1	-1*(-900+600)= $300	

Step 2: Determine DAM_MWP^{p2} in Pass 2

$DAM\_COMP1 = -1 \times [OP(DAM\_QSI^{p2}) - OP(DAM\_EOP)$

DAM_COMP2		
	$OP(DAM\_QSI^{p2})$	OP(DAM_EOP)
Revenue	40MW x $20 = $800	20MW x $20 = $400
Cost	40MW x $50 = $2000	20MW x $50 = $1000
Net	$800 -$2000 = -$1200	$400 - $1000 = $ -$600
DAM_COMP1	-1*(-1200+600)= $600	

DAM Reliability Scheduling Uplift – Scenario 1

Step 3: Determine total incremental DAM_MWP paid to import

DAM_P2_PMT = -1 x (DAM_MWP^{p2} – DAM_MWP^{p2})

DAM_P2_PMT = -1 x ($600 - $300)
= -$300

Step 4: Determine NDL that was over-forecast in DAM

DAM_NDL_OF = DAM_QSW - AQEI

DAM_NDL_OF = 10000MW – 9950MW
= 50MW

The remaining -$37.50 (-$300 + $262.50) will be allocated to loads and export on a pro-rata basis

Step 5: Calculate each virtual allocation amount

DAM_NDL_OF = DAM_QSW - AQEI

Virtual Resource	Virtual DAM Injection	DAM_NDL_OF	Virtual DAM injection/(Total Virtual DAM injection + DAM_NDL_OF)	DAM_P2_PMT	DRSU charge
V1	50	50MW	50/(350+50) = 0.125	-$300	-$37.5
V2	100		100/(350+50) = 0.25		-$75
V3	200		200/(350+50) = 0.50		-$150
				Total	-$262.5

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Next Steps

Next Steps:

Throughout December and January: Stakeholders can review appendix material, and request additional examples or scenarios through engagement@ieso.ca

Mid-January: Segmented discussions with stakeholders to review examples/scenarios (Sign Up: https://www.ieso.ca/en/Market-Renewal/Stakeholder-Engagements/Implementation-Engagement-Market-Rules-and-Market-Manuals

February 21: Comments/feedback on market rules and market manuals due to IESO

Thank You

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