Stakeholder Feedback Form: MRP Energy Detailed Design

Design Document: Grid and Market Operations Integration

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Feedback provided by:

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The IESO is posting a series of detailed design documents which together comprise the detailed design of the MRP energy stream.

This design document is posted to the following engagement webpage: http://ieso.ca/en/Market-Renewal/Energy-Stream- Designs/Detailed-Design.

Stakeholder feedback for this design document is due on July 31, 2020 to engagement@ieso.ca.

Please let us know if you have any questions.

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General feedback on the Detailed Design Document

Ontario Power Generation's (OPG)'s detailed review comments for the Grid and Market Operations draft detailed design are provided in the table below. The following list provides a brief summary of the main themes in our comments. OPG looks forward to working with the Independent Electricity System Operator (IESO) to address/mitigate the issues we've identified so the final design can maximize market efficiency and minimize costs to ratepayers. More details on each of the following items is included in the detailed review comments.

1. First run of the pre-dispatch (PD) engine at 20:00 is too late in the day to update hydroelectric offers to reflect evolving water conditions and plan effectively for next day's water. OPG proposes this be changed to 18:00 to allow more flexibility and time for adjustments prior HE1 of the next dispatch day.
2. Design characteristics will require the use of outage slips to de-rate capacity for changes in head & flow conditions, which would require excessive submission of outage slips. This could become unmanageable for both market participants and the IESO.
3. The design details imply that hydroelectric facilities can spill as a normal course of action and are dispatchable on 5-minute intervals. Sluice gates were not designed to be dispatchable at this frequency and should not be considered as a tool to facilitate dispatch instructions.

Section 1 General Hydroelectric Parameters

Detailed Comment: Impacts of losing 2nd day-ahead offer window for hydroelectric resources

Hydroelectric operations are complex due the dynamic nature of water conditions, operating restrictions, cascade dependencies and the various environmental/regulatory constraints that need to be respected. These changes to conditions can occur throughout the day, with various inputs required from a variety of entities. In today's non- financially binding day ahead commitment process (DACP) energy limited resources (ELRs) such as hydroelectric facilities have a second offer window to revise offers to ensure schedules are feasible before the final day-ahead (DA) engine runs to mitigate the identified risks.

OPG believes a 2nd Offer Window is needed to address many of these issues and to help create a more accurate picture for the day ahead market (DAM). Without this 2nd offer window participants will be forced to offer into the market less effectively/efficiently, as they may not have all the required information (e.g. from various regulatory stakeholders) to make financially binding decisions in the DAM.

In previous stakeholder engagements the IESO committed to building a hydroelectric optimization module that would incorporate a set of hydroelectric parameters as constraints with its DAM and enhanced real-time unit commitment (ERUC) engine vendor. However, after reviewing the detailed design documents thus far, the hydroelectric parameters will only account for a few circumstances, and the frequency of which changes can be made to the parameters falls below the necessary requirements to operate hydroelectric resources/facilities effectively. It is important the IESO understands the dynamic challenges hydroelectric facilities face when it comes to water management, and for these assets to be utilized effectively and efficiently to maximize the benefits to the system/consumer they need to be given flexibility.

OPG understands the need to be technology agnostic between different energy resources but given the dynamic nature of river systems and the controlling influence from a wide variety of external/regulatory stakeholders, there is an inherit difference between technologies and fuel types. If a 2nd offer window for hydroelectric resources isn't implementable, OPG recommends the language around changing/modifying hydroelectric parameters be changed to allow for more operational flexibility. The recommended changes to those parameters are provided in OPG's comment submission for the Offers, Bids and Data Inputs Detailed Design (see OPG's comments #11-17 from OPG's Offers, Bids & Data Inputs comments).

Section 2 General Resource Aggregation

Detailed Comment: Clarification on how river compliance aggregation will be maintained in the new market.

In section 3.7.2.2, the design states:

"To manage changes in real-time conditions, the RT calculation engine will be permitted to dispatch hydroelectric resources for more or less energy than scheduled for that dispatch hour by the DAM and PD calculation engines. As quick start facilities, dispatchable hydroelectric generation facilities must be capable of responding to five-minute dispatch instructions.

For these dispatch instructions to remain feasible, new and existing mechanisms will be used to inform the RT calculation when the dispatchable range of a hydroelectric resource is no longer available. New mechanisms include the ability for registered market participants to reflect must run conditions in advance of the dispatch hour. Existing mechanisms include the ability for registered market participants to adjust offer prices for energy, use compliance aggregation, and submit outages. The IESO will also retain the ability to apply manual constraints for the resource on behalf of the registered market participant."

Compliance aggregation remains an important mechanism used by hydroelectric stations to balance physical/operational constraints while following 5-minute dispatch. OPG is interested in understanding if the IESO is contemplating any changes to the existing rules around the utilization of compliance aggregation and recommends that any proposed changes be stakeholdered with market participants.

Section 3.3.3 Market Timing

Detailed Comment: Change requirement to submit AGC availability from 08:00 EPT to 09:00 EPT

In section 3.3.3, the design states:

"Ancillary service providers within the IESO-controlled grid will continue to be eligible to provide regulation services under the terms of Automatic Generation Control (AGC) contracts. Under these contracts, ancillary service providers are currently required to submit regulation services availability data prior to 09:00 EST on the pre-dispatch day. In the future market, this requirement will be changed to 08:00 EPT to reflect the change in timing of the DAM scheduling process (see section 3.6.1)."

Similar to current timelines, OPG recommends that ancillary service providers must submit regulation services availability data prior to 09:00 EPT (i.e. one hour prior to the DAM submission window). This would allow hydroelectric ancillary service providers to assess the most up to date conditions impacting their ability to provide AGC. Forecasting conditions for AGC requires upstream flow information involving other stakeholders/regulatory parties and assessing the most current flow conditions and expected schedules for the current day. This would allow the IESO until 09:30 EPT to communicate their acceptance of AGC schedules, which would leave market participants 30 minutes to revise corresponding offers to the DAM.

Section 3.3.3 AGC

Detailed Comment: Automation of AGC submission process

The current market process of submitting AGC schedules and revisions to the IESO is a manual process that could be better automated during Market Renewal. Automation may reduce barriers to new technologies entering the AGC market. OPG proposes the IESO incorporate the submission of AGC schedules into the same tool/system used for offers/bids submission in the new market.

Section 3.3 Market Timing

Detailed Comment: RTM mandatory window

Figure 3-2 shows the real-time market (RTM) Mandatory Window as 110 minutes. The IESO should consider shortening the RTM mandatory window time frame from 110 minutes to 90 minutes. A shorter window would be beneficial to market participants as it would provide resources additional flexibility / time to adjust to offers based on changing conditions (e.g. hydroelectric flow, forced outages etc.). In NYISO, the mandatory window is only 75 minutes.

Section 3.3.5 Hydro Parameters

Detailed Comment: Updates to daily dispatch data

In Section 3.3.5 the design states:

"In the future, daily dispatch data submissions will be used to determine a generation facility's DAM and PD schedule and/or commitments. The following existing and new parameters will be available for submission as daily dispatch data:

- Linked resources, time lag and MW ratio;
- Forbidden regions;
- Maximum daily energy limit (Max DEL);
- Minimum daily energy limit (Min DEL);

- Single cycle mode;
- Maximum number of starts per day;
- Minimum loading point (MLP);
- Minimum generation block run-time (MGBRT);
- Minimum generation block down time (MGBDT);
- Lead time;
- Ramp up energy to MLP; and
- Steam turbine 10-min OR contribution.

These parameters will be subject to different submission and revision rules than hourly dispatch data, as described in the following sections."

OPG recommends that changes to daily dispatch data inputs should be permitted hourly for physical/operational constraints. Parameters such as Linked resources, time lag, MW ratio and forbidden regions can change hourly based on physical/operational constraints that impact head calculations such as inflows, available units, expected upstream/downstream discharges, etc... The detailed recommended changes to those parameters are provided in OPG's comment submission for the Offers, Bids and Data Inputs Detailed Design (see OPG's comments #11-17 from OPG's Offers, Bids & Data Inputs comments).

Section 3.3.5 Hydro Parameters

Detailed Comment: Naming Consistency for "Linked Resources, Time Lag and MW Ratio" parameter

In the Grid & Market Operations Integration detailed design document this hydro parameter is referred to as "Linked Resources, Time Lag and MW Ratio" but in the Offers, Bids and Data Inputs detailed design it is referred to as "Linked Resources, Time Lag and MWh Ratio". The IESO needs to clarify which name is correct (MW or MWh) and be consistent across all of the detailed design documents.

Section 3.3.7.2 Market Ops

Detailed Comment: Determination of ADE for hydroelectric needs revisiting

In Section 3.3.7.2 Restrictions on Energy Offer/Bid Quantity – Availability Declaration Envelope (ADE), the design states:

"Similar to today's ADE requirement, registered market participants submitting dispatch data on behalf of a dispatchable generation facility, dispatchable load or hourly demand response resource for the real-time market will be restricted from increasing their energy offer quantity or energy bid quantity above the quantity submitted for the DAM, for any dispatch hour of the dispatch day."

If the ADE is retained under the DAM, OPG believes the method for which ADE is determined and used for hydroelectric resources would need to be revisited. A methodology to incent hydroelectric resources to more accurately reflect their capability based on expected conditions at the time of offer submission rather than trying to ensure adequate ADE in real-time.

If ADE is calculated based on DAM resource offers, an alternative solution would be to allow RT offers to exceed DAM ADE by a reasonable margin (similar to compliance deadband) to recognize variability of water conditions (e.g. head change MW) between DA and RT timeframes. This solution would also provide flexibility for nuclear resources that experience varying lake temperatures between DA and real-time (RT) that affect overall MW output.

Market Manual 9, Part 9.4 section 4.5.5.3 states, "You may make small increases to your ADE without requesting our approval. These increases must be limited to 2% of the ADE established in the DACP Schedule of Record, or 10 MW, whichever is less." In the case of hydroelectric, a unit with ADE of 50 MW is currently restricted to an increase of 1 MW in real-time which is not representative of head based capacity changes. The IESO should increase the ADE deadband to 15% or 10 MW, whichever is less, to represent the unique characteristics of hydroelectric operation. Otherwise, market participants will take on additional risk of infeasible day ahead financially binding schedules to allow for head-based changes in real-time.

Section 3.3.7.2 Market Ops

Detailed Comment: Process for evaluation / approval of ADE exceptions

OPG recommends the IESO develop a process for evaluation and approval of ADE exceptions that has ease of implementation and places the least amount of burden on IESO control room staff. The reasons for requesting an ADE exception and receiving approval should be expanded to include:

- changes to hydroelectric physical/operating constraints impacting head based capacity,
- delays to an outage (transmission/generator) or a derate, etc.

OPG suggests that IESO stakeholder a list of possible ADE exceptions during technical discussions with market participants.

Section 3.4.1 Market Timing

Detailed Comment: Changes to conditions that warrant re-running the DAM Calculation Engine

In section 3.4.1 the design states:

"In the future market, there will be a single DAM calculation engine run. The IESO will provide IESO data inputs that reflect the best information available prior to the DAM submission deadline of 10:00 EPT. IESO inputs used by the day-ahead market will not be modified to reflect changing system conditions after 10:00 EPT. IESO inputs into the DAM calculation engine will only be modified after 10:00 EPT to correct an input error that results in invalid day ahead market results as discussed in Section 3.5.3.1, Re-running the DAM Calculation Engine."

The IESO should clearly define and provide examples around what types of "input errors" will be modified after 10:00 EPT that would result in invalid DAM results.

In section 3.5.3.1, Re-running the DAM Calculation Engine it states: "In the future day-ahead market, no changes to dispatch data will be permitted after 10:00 EPT, unless there is an IESO tool failure. During the DAM scheduling process, the DAM calculation engine will not be re-run for changing system conditions. Any changes will be considered in subsequent evaluation processes such as pre-dispatch."

OPG believes conditions that warrant a re-run of the DAM Calculation Engine should include changes to system conditions such as transmission outages, which can drastically change the day ahead financially binding schedules for market participants. The IESO needs to model transmission constraints as accurately as possible in the day ahead to mitigate the buyback risk associated with infeasible day ahead schedules. MPs should not be held financially responsible for inaccurate constraint modelling. Becoming more inflexible in the future day-ahead market with regards to what necessitates a re-run of the DAM calculation engine could lead to market participants being more risk adverse in a financially bound DAM.

OPG suggests the IESO investigate the need to provide reporting related to "balancing congestion", i.e. where there are differences in transmission congestion in the real time market as compared to the day ahead market. PJM provides a variety of reports related to balancing congestion, and charges associated with it.

Section 3.4.1 Additional Reporting

Detailed Comment: Need for criteria & standard reporting format for advisory notices

In section 3.4.1 the design states:

"IESO data inputs related to reliability requirements, demand forecasting and centralized variable generation forecasts are made public to market participants through public reports and advisory notices. The timing of report publication is detailed in the Publishing and Reporting Market Information detailed design document. Advisory notices will continue to be ad hoc and present additional information not available through public reports."

OPG recommends, the IESO consolidate reporting processes to include standard reporting and timing of the information that would be contained in an "Advisory Notice" into the Adequacy report. The report would populate when an "Advisory Notice" is issued and be empty for periods where there are no notices. This would allow market participants to automatically and easily retrieve and archive this data for analysis or reference. Formal reporting of "Advisory Notices" will increase transparency and efficiency after market renewal.

Section 3.4.2.1 Additional Reporting

Detailed Comment: Condense reporting of reliability requirements

In section 3.4.2 the design states:

"Reliability requirements are operational inputs produced by the IESO to satisfy grid reliability and security standards as per NERC, NPCC and IESO market rules. As defined in the Offers, Bids and Data Inputs detailed design document, these reliability requirements are:

- Maximum Import/Export Limits;
- Net Interchange Scheduling Limit (NISL);
- Lake Erie Circulation Forecast;
- Minimum/Maximum Area Operating Reserve;
- Operating Reserve Requirements;
- Regulation Capacity Requirements;
- Security Limits; and
- Reliability Constraints."

There is an opportunity to increase efficiency and transparency if the IESO were to consolidate similar information and publish the consolidation in the same reports. For example: Publish Maximum Import/Export Limits, Net Interchange Scheduling Limit (NISL), and Lake Erie Circulation Forecast in the one report, all Operating Reserve data in one report, and security limits and reliability constraints together in a separate report. This approach would allow a market participant to look at a one report for similar information instead of cross-referencing multiple reports.

Section 3.4.2.4 Additional Reporting

Detailed Comment: Publishing of operation security limits (OSLs)

In Section 3.4.2.4 the design states:

"Minimum scheduling constraints will be applied and identified as reliability constraints to ensure appropriate settlement treatment."

The IESO should publish reliability constraints in private reports to market participants. This will allow market participants to reconcile make-whole payments in DA and RT markets. These reports should be published in DA, PD, and RT timeframes, as well as, part of Settlement data files.

Section 3.4.3 Hydro Parameters

Detailed Comment: Network model logic updates

In section 3.4.3 the design states:

"The IESO will continue to monitor and update network model inputs related to:

- outages;
- equipment status; and
- telemetry."

There is an opportunity for IESO to revisit its network model logic to use hydroelectric unit breaker position directly to determine if a unit is synchronized instead of the inferred logic used in the current network model.

Section 3.6.1 Market Timing

Detailed Comment: Benefit of advancing the time of the first pre-dispatch run

The design shows that the first PD run is performed at 20:00 EST, which is up to 6.5 hours after the DAM schedules and prices are published. OPG has multiple concerns with this approach as there is limited opportunity for market participants to review and update offers required for the dispatch day. Market participants will only be able to view 2 pre-dispatch runs before the mandatory window closes for HE1 of the next dispatch day. OPG recommends advancing the first run of the PD to 18:00 EST. This would give market participants an additional 2 hours to modify their offers to ensure that schedules produced by the DAM engine runs are feasible and reflect operational capability in RT.

Unanticipated outages, early return from an outage or revised demand and variable generation forecasts due to rapidly changing weather conditions are unavoidable. Capturing these changes in an earlier PD run would improve planning for market participants. For example, at 18:00, given an increased view of SBG for the dispatch day, hydroelectric resources may be able to run additional water within the remaining hours of the day to help mitigate the forecasted SBG. The earlier PD run will also facilitate greater transparency for the additional binding start-up commitments for NQS facilities that may be required prior to the first PD run as described in Section 3.6.2.1 and referenced in comment #31.

From OPG's previously submitted comments during the high level design phase, a 20:00 initial pre-dispatch run does not provide opportunity for gas suppliers (unless they have a fuel transportation contract) to procure additional gas that may be required for the next day between HE1-HE15 should the pre-dispatch results identify the need. An 18:00 initial run would provide suppliers a minimum amount of time required to meet the North American Energy Standards Board (NAESB) ID3 deadline at 19:00 to procure any gas between 22:00 today and 9:00 tomorrow.

OPG understands the IESO investigated four options to facilitate an 18:00 publishing of ERUC that would span the following day and determined that none of the options were workable. OPG recommends the IESO reconsider advancing the first run of pre-dispatch to 18:00 EST now that the software vendor has been acquired and there is a greater certainty around actual software capabilities. If facilitating an 18:00 publishing of ERUC is still not feasible, please provide the rationale on why it isn't possible.

Section 3.4.4.2 Additional Reporting

Detailed Comment: Report needed to indicate when in override mode

The IESO adjusts the centralized variable generation forecast to better align with observed variable generation output trends and the design states that:

"in the future, the IESO will apply overrides on a zonal basis to ensure that variable generation forecasts in each zone reflect conditions in each zone."

The IESO should create a report to indicate when and in which zone the IESO is in manual or override mode to provide transparency to market participants. This will allow market participants to respond to variable generation forecast changes that could potentially impact the generation schedule.

Section 3.4.4.2 Forecasting

Detailed Comment: Centralized variable generation forecast broken down to zonal level

The design states:

"In the future, the IESO will apply overrides on a zonal basis to ensure that variable generation forecasts in each zone reflect conditions in each zone. Global overrides will only be used to address reliability concerns when timeframes do not permit the application of zonal overrides."

For market participants to adequately manage their assets (generation or load) in a market with LMP's, OPG suggests the IESO include a zonal breakdown of the centralized variable generation forecast for each of the nine zones in the new market. Market Participants should have transparency with regards to the forecasted amount of variable generation in the respective zones where their resources reside. Potential deviations in forecasted variable generation could have significant impacts to market participant resources, particularly if they are providing generation in constrained areas. OPG suggests the zonal breakdown of the centralized variable generation forecast be included in the Adequacy report published two times per hour.

Section 3.4.5 Forecasting

Detailed Comment: Maintenance of traditional hourly province wide Ontario Demand Forecast

The design states that the IESO will produce the existing province-wide demand forecast as the sum of the four separate demand forecast areas. Forecasting errors can be magnified at lower load levels and OPG suggests that the IESO continues to publish the traditional hourly province wide Ontario Demand forecast to compare how the new methodology compares to the current one.

Section 3.4.5 Forecasting

Detailed Comment: Need for 5-minute demand forecast adjustment at zonal level

The design states:

"In the future market, the IESO will continue to have the ability to adjust the 5-minute global demand forecast. However, this global demand forecast adjustment will be apportioned to each demand area based on the relative demand in that area.

OPG recommends that if the IESO elects to produce demand forecasts on a zonal level in DAM and PD, the 5- minute forecast adjustment should also be done on a zonal level. This is because with Ontario's large geographic area and rapidly changing weather conditions across the province, load could be increasing in one zone and declining in another, resulting in large forecast errors and market inefficiencies. A global adjustment would not be able to capture this.

There should be full market transparency on forecast changes including but not limited to demand response (how much and when and in which zones), and highly variable embedded generation (i.e. solar, wind, batteries, etc.) Full disclosure on these elements impacting zonal/global demand is needed for grid reliability and market participant decision making. OPG recommends this information be provided in the Adequacy report published two times per hour.

Section 3.5.2.2 Market Ops

Detailed Comment: Changes to DAM dispatch data following tool failures

The design states:

"In the future DAM, these actions will continue to be used with one exception: additional inputs and changes to dispatch data for the DAM will not be considered or requested by the IESO after the close of the DAM submission window unless there is an IESO tool failure. Therefore, to detect issues earlier and provide the opportunity for a market participant to re-submit dispatch data prior to the close of the submission window, the IESO will perform an early assessment to determine if sufficient dispatch data was submitted to satisfy the day ahead forecast demand."

OPG is seeking clarification of when the IESO is planning on performing the early assessment. Also, when these issues arise, OPG recommends that all market participants are informed and given the opportunity to make changes to their DAM dispatch data.

Section 3.5.2.3 Reliability Constraints

Detailed Comment: Changes to reliability constraints following DAM

From 3.5.2.3 in the design document it states:

“To ensure resources required are scheduled even if uneconomic, the IESO will create a minimum scheduling constraint on the facility(s) as an input to the calculation engine.”

If constraints are identified prior to the DA submission window, they will be applied as inputs into the DAM calculation engine. OPG is seeking clarification on what the result will be if the constraint identified in DA is no longer binding in pre-dispatch and real time. Will the constraints be maintained, or will the market participant be liable for the buy back in RT? If the constraint is captured in the DAM calculation engine, the contrained resource should be economic by virtue of the LMP price (Marginal Congestion Cost (MCC) component). Resources requiredin the DAM should never be scheduled uneconomically.

Section 3.5.2.4 Operating Reserve

Detailed Comment: Incorporate Flex OR into DAM reliability pass

The design states:

"The ability to schedule Flex OR will be incorporated into the day-ahead market. A new process will enable the IESO to determine if Flex OR is required as well as the quantity for the day-ahead market and notification will be provided to market participants."

This should be part of the reliability pass of the DA calculation engine and additional units required to provide OR should be scheduled accordingly.

Also, in the Market Surveillance Panel Report Issued on July 30th, 2020 it states:

“The IESO’s solution is to procure a predetermined amount (200MW) of additional Operational Reserve (OR) intended to schedule a generator(s) to come online that otherwise would not be committed and provide greater capacity than their scheduled amount – providing “spare energy” to address the need.

The solution lacks specific criteria for when it should be invoked. It relies largely on the discretion of the IESO to determine when spare energy is required, which leads to inconsistent market outcomes. The solution also does not align with actual needs due to its “all or nothing” design. Regardless of the need for flexibility, the amount scheduled is uniformly 200 MW. If the solution does not produce the desired amount of spare energy, out-of-market actions – which it was explicitly intended to reduce – are used.

The current solution was intended to be temporary, but is now expected to remain in place beyond the Market Renewal Program (MRP), which is years from being completed.”

OPG would suggest the IESO review their methodology of addressing system flexibility needs as the MSP has recommended the IESO re-consider its current approach and develop a long-term, cost-effective solution. The IESO should also ensure they consult and solicit input from stakeholders as part of their process with the OEB which can be done through various existing IESO stakeholder engagements (e.g. OR Accessibility, MRP).

Section 3.5.3.1/3.9.1.1 Additional Reporting

Detailed Comment: Reporting on DAM failure and re-run of DAM engine

In section 3.5.3.1 the design states:

"The IESO will continue to have the ability to correct IESO inputs and re-run the DAM calculation engine in order to produce valid DAM results due to IESO errors or calculation engine issues. When a re-run occurs, notification will be provided to market participants as well as information on any revised inputs."

The IESO should publish a report rather than send notification when the DAM is re-run during a day; for transparency the report should include information on the revised inputs.

Please clarify if additional Flex OR is procured, reserve requirement in RT will not be decreased as this would cause financial bookout complications.

Section 3.5.3.3

Detailed Comment: Cost compensation following DAM calculation engine failure

The design states:

"In the future day-ahead market, a failure will be declared if valid results cannot be produced by approximately 15:30 EPT."

Delays or failures of the DAM may lead to non-quick start units missing the opportunity to procure an appropriate amount of gas in the ID2 gas window that closes at 14:00 EPT. This may lead to increased costs to procuring gas that were not anticipated during day ahead submission timelines. OPG recommends the IESO create a process that allows market participants to recover their costs if the costs of the subject commodities increase due to the uncertainty caused by delays or failures of the DA calculation engine.

Section 3.5.4.2 Hydro Parameters

Detailed Comment: Number of forbidden regions allowed

Both Offers, Bids, and Data Inputs and Grid & Market Operations Integration Design Documents do not mention the number of forbidden regions that will be allowed for each resource type. In the current market there are only three forbidden regions per resource aggregate. OPG proposes this be expanded to at least 8 to reflect one resource that contains 8 units along with multiple resource aggregates that contain more than 3 units.

Section 3.5.4.2 Hydro Parameters

Detailed Comment: Clarifications on max number of starts per day (MNSPD) parameter

In section 3.5.4.2 the design states:

"In the DAM, the sum of resource starts over the 24-hour look-ahead period will be no greater than the submitted maximum number of starts per day value. For a hydroelectric resource registered as an aggregate of generation units, starts will be counted based on registered start indication values for the resource."

OPG recommends the maximum number of starts per day is applied at the unit level. For example: if a resource type has 5 generating units then the number of starts would be the maximum number of starts per day submitted multiplied by 5.

In Offers, Bids, and Data Inputs Detailed Design Document Section 3.4.2 the design also states:

"MNSPD submitted as dispatch data must be a number between 1 and 24 starts per day. If MNSPD is not submitted, a default value of 24 starts per day will be used by the DAM calculation engine. The PD calculation engine will be enhanced to use the same default value the DAM calculation engine uses."

OPG recommends the IESO re-assess the default value of 24 depending on whether MNSPD is at the resource type level of the unit level.

OPG recommends the Number of Starts Tracking Report is published on an hourly basis and should include IESO inferred number of starts per unit for a resource type with multiple generating units for all historic hours of the day on an hour by hour basis. This level of detail will allow market participants to proactively assess the accuracy of the inferred calculation.

A process should also be developed that allows the market participant to either correct the number of starts as reported in the Number of Starts Tracking Report or NULL the Maximum Number of Starts per Day parameter through daily dispatch data submission. For example, starts related to return to service testing may exceed the number of starts per day submitted for a resource type that may limit its ability to generate in future hours resulting in market inefficiencies if market participants are not able to modify the parameter throughout the day.

Section 3.5.4.2 Hydro Parameters

Detailed Comment: Linked Resources, Time Lag and MW ratio parameter

With regards to Linked Resources, Time Lag and MW ratio parameters, please confirm the following:

- Are linked resources based on aggregate or station level? For example, will MPs have the ability to link all units at Station X to Station Y, or can market participants link resources based on aggregates (i.e. injection point)? For example, Station X and Y each have 2 aggregates and Station X-AG1 is linked to Station Y-AG1 and Station X-AG2 is linked to Station Y-AG2?

Certain hydroelectric stations are restricted in the number of units that can be dispatched to start/stop generating simultaneously, this effectively results in a delay between when units at the same station can be started. To produce a feasible schedule, OPG suggests the ability to link aggregates belonging to the same station (e.g. link AG1 and AG2 belonging to Station X), with an appropriate lag between unit starts/stops to reflect this restriction. OPG welcomes further discussion or alternative solutions to address the operational concern.

Section 3.5.5.1 Additional Reporting

Detailed Comment: Details on private reports on mitigation events

In section 3.5.5.1, the design states:

"Market participants will also receive private reports on any mitigation actions that were taken by the calculation engine."

In the Market Settlements, section 3.13.1, the design states:

“When a resource meets the conditions to carry out a make-whole payment mitigation impact test, the IESO will determine what the settlement amount would have been, if the dispatch data had been subject to mitigation based on the set of conduct and impact thresholds that apply to the most restrictive constrained area. The most restrictive set of thresholds for the dispatch data will be determined over the period that the settlement amount is calculated. Therefore, if the settlement amount is calculated over multiple hours, the hour with the most restrictive set of thresholds will determine the set of thresholds used in all hours of the calculation."

The IESO should publish private reports including the most restrictive constrained areas regardless of whether a mitigation event occurs. This is required since the make-whole payment mitigation test is independent of mitigation events and depends on the thresholds for the most restrictive constrained area.

Section 3.5.4.1/3.5.5.3 NQS

Detailed Comment: Minimum constraints in pre-dispatch to respect DAM schedule

Section 3.5.4.1 states that the DAM calculation engine will be used to create financially binding schedules and operational commitments for NQS generation including the ramp up energy to MLP.

Section 3.5.5.3 states:

“NQS generation facilities and pseudo-unit operational commitments made in DAM will continue to be passed to PD through minimum constraints for the generation facility’s MLP. The period of the operational commitment and resulting constraint applied to PD will be equal to the MGBRT hours for each separate start. The constraint will not be for the entire duration of the DAM schedule.”

OPG is seeking clarification if minimum constraints applied in pre-dispatch will coincide with the first hour that a unit is scheduled at or above its MLP in the DAM financially binding schedule. For example, from Figure 3-20, it appears that the minimum constraint to MLP for MGBRT is applied starting at 09:00 which is the first hour where DAM financially binding schedule is at or above MLP.

Also, can the IESO confirm that if a MP chooses to withdraw from their DAM Operational Commitment, the minimum constraint to MLP for a units MGBRT will not be transferred to the PD calculation engine? The design document should state how the calculation engines would handle instances of operational commitment withdrawal for NQS generators.

Section 3.5.5.3 Trading/Interties

Detailed Comment: Impact of market participant changes to intertie offers/bids in PD

The design states:

"In the future market, import and export schedules resulting from the DAM will be passed onto PD in order to inform scheduling limits for import and export offers and bids in the PD evaluation."

If a market participant changes its intertie bids/offers after the release of the DAM schedule, OPG is seeking clarification on whether or not future PD run intertie schedules will diverge from the DAM schedule based on the economics of the revised offer/bid data?

For example, a market participant is economically scheduled to export 50 MW to MISO in the DAM for HE8-HE16. In HE5 of the dispatch day, the market participant's lower its offer price such that it is no longer economic to flow its DA commitment. OPG recommends that all future hours of the next PD run reflect the revised offers for the DA committed, i.e. a 0 MW export schedule for HE8-16.

Published reports for all future hours should reflect import and export schedules based on a market participant's latest offers/bids to increase market efficiency.

Section 3.6.2.1 NQS

Detailed Comment: Public reporting of reliability commitments prior to first PD run

The design states that the IESO will be able to issue a binding start up instruction before the first PD calculation engine run at 20:00 EST in response to changing system conditions for the dispatch day that materialize after the DAM submission window.

Rather than issuing a system advisory notice to inform market participants when a reliability commitment has been given to a NQS in advance of the first PD run, OPG recommends that the IESO publish a public report that includes the specific hours of the day that a commitment was given.

System conditions for the dispatch day can change drastically from when the DAM submission closes up to first PD calculation engine run for reasons including but not limited to: forced unit outages, early return from an outage, and weather forecasts that affect variable generation output. All of these potential changes further support OPG's proposal to advance the first PD calculation run to 18:00 EST.

Section 3.6.2/3.8.1.1 NQS

Detailed Comment: Method for notification of binding start-up commitment

It is noted in Section 3.8.1.1 that:

"The IESO will issue an automated notification of commitment in the form of a binding start-up instruction in the PD."

"Market participants must electronically confirm receipt of the notification and their ability to comply with the start-up instruction no later than 15 minutes prior to the start of the next dispatch hour. The IESO must continue to be notified promptly if a generation unit is unable to meet the commitment."

Additional information is required on the mechanics, structure and IT requirements of the automated notification of commitment provided by the IESO and how market participants will submit confirmation of ability to comply. Due to the limited time available to market participants to respond to the binding start up instruction, there is concern about the reliability of receiving and delivering timely confirmation and OPG recommends that IESO should also communicate binding start-up instructions verbally to market participants. In addition, market participants should notify the IESO verbally regarding their ability to comply with the start-up instruction.

OPG is seeking further information on the consequences for failing to respond to the start-up instruction within the 15-minute window identified.

Section 3.6.2.2 NQS

Detailed Comment: Eliminating the 2-hour notice prior to synch requirement for NQS resources

The current market rules require that market participants provide 2-hour notice prior to synchronization to the grid. The new design states:

“The binding start-up instruction will be issued by the last pre-dispatch run that respects the lead time dispatch data parameter of the resource, while ensuring that it will achieve its MLP for the first hour of its operational commitment.”

OPG proposes that the current rule for market participants to provide 2-hour notice prior to synchronization be eliminated. Market participant acknowledgement and confirmation of a binding start-up instruction should replace the current notification to synchronize rule.

Section 3.8.1.2 NQS

Detailed Comment: Method of notification of de-commitment

The design states:

“The IESO will issue an automated notification of de-commitment when the PD calculation engine has no longer scheduled the NQS generation unit in the following hour. Market participants will need to electronically confirm receipt of the notification and their ability to comply with the de-commitment no later than 15 minutes prior to the start of the next dispatch hour.”

Additional information is required on how the IESO Notification of de-commitment will be issued and how will market participants submit confirmation of ability to comply. Due to the limited time provided to respond to the notification of de-commitment, there is concern about the reliability of receiving and delivering timely confirmation and OPG recommends the IESO should also communicated e-commitment notifications verbally to market participants. Further, market participants should notify the IESO verbally regarding their ability to comply with the de-commitment.

OPG is also seeking further information on the consequences for failing to respond to the de-commitment notification within the 15-minute window identified.

Section 3.8.1.2 NQS

Detailed Comment: Eliminating the 1-hour notice prior to de-synch requirement for NQS resources

The current market rules require market participants to provide 1-hour notice prior to de synchronization from the grid. The new communication protocol cited in comment #34 should replace the market participant's current requirement to provide 1-hour notice prior to a de-synchronization.

Section 3.6.2.2 NQS

Detailed Comment: Ability to provide multiple 'ramp energy to MLP' values for this parameter

Figure 3-22 provides an example of a binding start up instruction with the generator requiring two hours to ramp up to MLP. OPG proposes that market participants should be able to provide multiple 'Ramp Up Energy to MLP' inputs for this parameter. For example, HE15 - 20 MW and HE16 - 200 MW should not be represented linearly by 110 MW (the average) for each hour. From this example, the use of average ramp values causes discrepancies and market inefficiencies in both hours that may be avoidable by allowing two separate values for each ramp hour.

Detailed Comment: Need to modify MGBDT & lead time parameters intra-day

OPG is concerned the use of predefined MGBDT & Lead times to determine a future commitment may not accurately reflect the condition of a plant. The condition of thermal plants may vary start-to-start, and thus modifications to hot, warm and cold lead times may be necessary during the day. OPG requests the IESO publish an hourly standardized confidential report to indicate the inferred state of a NQS unit and suggests that a mechanism be put in place that allows modification of the lead time throughout the day to ensure the accurate state is reflected in the market.

Detailed Comment: Standalone Pre-dispatch operational commitment ahead of a DAM operational commitment

IESO identifies an example of a stand-alone PD operational commitment for a NQS generation facility that also has a DAM commitment in figure 3-27. Section 3.7.2.1 states:

"If after the first commitment the RT calculation engine determines that the NQS generation unit is economic to remain in-service in real-time, the RT calculation engine will continue to keep it online and not dispatch it below MLP. If the 5-minute dispatches overlap with the MGBDT such that the generation unit will not be able to comply with a future commitment, the IESO will perform a reliability assessment. If there is an immediate reliability need, the IESO will keep the generation unit in-service until the future commitment starts, otherwise it will enforce the PD de-commitment decision and the RT calculation engine will ramp the generation unit down."

The proposed design could make market participants financially responsible for not meeting a DAM commitment through no fault of their own. If the IESO commits a NQS unit ahead of its DAM commitment, the unit should be constrained on to at least its MLP until the start of its of DAM commitment if it is unable to respect its MGBDT if it is de-committed from the first stand-alone PD operational commitment. For example, the NQS unit stand-alone pre-dispatch commitment identifies that it is no longer economic after 11:00, and it has a DAM commitment starting at 16:00. The MGBDT is 6 hours. If the NQS unit is de-synchronized shortly after 11:00, it is not possible to re-synchronize the unit in time to meet its DAM operational commitment due to the physical/operating constraints of the 6-hour MGBDT requirement. If the MGBDT cannot be respected to re-synchronize a unit in time to meet its DAM financially binding schedule, the NQS should be constrained on to its MLP until the start of its DAM commitment.

Detailed Comment: Compensation following cancellation of a DAM or PD NQS commitment

OPG understands the IESO may cancel a DAM or pre-dispatch operational commitment at any time for reliability, security or adequacy reasons. A facility may be financially out of pocket if the cancellation of an operating commitment results in charges for placing unused gas back into storage. These charges, which are directly associated with an IESO cancellation of a DAM or pre-dispatch commitment, should be recoverable through a make whole payment.

In Market Settlements Design, section 3.7.9, the design states:

"In the event that a generation unit is de-committed subsequent to receiving a binding start-up instruction, the generation unit will be compensated for any lost opportunity during the de-committed period through RT_MWP."

Details on the definition of the "de-committed" period are required - it should include ramp up energy to MLP, minimum generation block run time, and ramp down from MLP. A process is also required for market participants to recover costs not covered by real-time make-whole payments, such as, charges incurred for placing unused gas back in storage.

Detailed Comment: Figure 3-29 Timing of issue of PD commitment extension Example 2

Figure 3-29 shows the binding commitment to extend is issued 30 minutes past the hour for an extension that occurs in the first PD hour.

OPG would like some clarity around the process with regards to how these binding commitments will be communicated to MPs. Clear communication channels/processes are required to ensure MPs will be able to meet their commitments.

Section 3.6.2.3 Hydro Parameters

Detailed Comment: Allow changes to hydro daily dispatch data with every hourly submission

The design shows that current hydroelectric daily dispatch data can only be revised hourly for the rest of the day due to a SEAL reason. OPG continues to propose that the hydroelectric parameters be expanded to allow for physical/operational constraints and allow market participants to make changes to the hydroelectric dispatch data with every hourly submission.

- Minimum & Maximum Daily Energy Limits (DELs)

IESO will track the actual energy produced using the following methodology: "Actual energy production gathered from operational telemetry will be recorded at the start of each dispatch interval in the real-time scheduling process and added to the running total of actual energy produced for the dispatch day. Registered market participants will have visibility of this running total through confidential reports."

The IESO's revised methodology of using actual energy produced gathered from operational telemetry rather than past pre-dispatch schedules will increase the accuracy of the actual energy produced reported. However, the MIN and MAX DEL amounts are reported in MWh whereas water management plans deal with volumetric amounts. The DEL parameter will need to be evaluated hourly based on the actual volume of water discharged, not MWh produced. Market participants will need the ability to modify the MIN and MAX DEL parameters hourly to true up the inherent differences between the units of measurement used. DEL calculations are most accurate when units operate at their best efficiency points. Refer to OPG Comment #13 from Offers, Bids and Data Input Detailed Design.

- Maximum Number of Starts Per Day

To track the actual number of starts, the IESO proposes that the same operational telemetry data gathered to track actual energy produced will be used at the start of each dispatch interval to track actual number of starts per day. As noted in comment 25 above, there may be errors in the number of actual starts tracked by the IESO. Market participants should be given the opportunity to update/correct the number of starts parameter on an hourly basis to ensure accurate dispatch data is used in the pre-dispatch calculation engine. Refer to OPG Comment #14 from Offers, Bids and Data Input Detailed Design.

- Forbidden Regions

The forbidden region of a hydroelectric generation unit corresponds to a range of MW values that will vary based on hydroelectric head-based calculation and the number of units available and expected to generate at a station. Hydrological changes including inflows, discharges, headwater and tailwater levels are some of the parameters that affect the hourly calculations of efficiency and capacity. As a result of these hourly changes, OPG recommends that market participants are able to modify forbidden regions on an hourly basis. Refer to OPG Comment #11 from Offers, Bids and Data Input Detailed Design.

- Linked Resources, Time Lag and MWh Ratio

The design states that market participants will be able to schedule intertemporal dependencies of cascade resources owned by the same market participant through the linked resources, time lag and MWh ratio parameters to ensure feasible schedules are generated. Although the physical distance between resources on a cascade river system are fixed, the time lag and MWh ratios can vary due to variables including but not limited to: wind velocity, inflows, and the differences between tailwater elevation of an upstream resource and the headwater elevation of the downstream resource. Hydroelectric conditions can vary throughout the day and market participants need the ability to modify and/or terminate linkages between resources during the day so that the intertemporal dependencies of cascade resources are accounted for in future PD runs. Refer to OPG Comment #16 from Offers, Bids and Data Input Detailed Design.

As hydroelectric conditions change, and unplanned outages and transmission constraints arise, market participants require the flexibility to modify the daily dispatch data parameters hourly to reflect physical operational restrictions.

Section 3.7.2.2 Hydro Parameters

Detailed Comment: Inefficiencies of RT scheduling require minimum generation constraints in the RT calculation engine

The IESO design states the following:

"Respecting the new dispatch data parameters will produce hourly DAM and PD schedules that hydroelectric generation facilities would be feasibly able to respond to if those schedules were to materialize as dispatch instructions in the real-time market.

To manage changes in real-time conditions, the RT calculation engine will be permitted to dispatch hydroelectric resources for more or less energy than scheduled for that dispatch hour by the DAM and PD calculation engines. As quick start facilities, dispatchable hydroelectric generation facilities must be capable of responding to five-minute dispatch instructions."

OPG supports the notion that as quick start facilities, dispatchable hydroelectric generation facilities are capable of responding to five-minute dispatch instructions. However, the hydroelectric parameters that market participants have elected to use to identify the physical and operational constraints of their resources to create feasible and efficient generation schedules in the day ahead and pre-dispatch timeframes must also be extended to the real-time calculation engine.

The design identifies the hydroelectric parameters that will be respected in the RT calculation engine are: Forbidden Regions, Min DEL, and Hourly Must Run. IESO has identified that for Min DEL, the real time engine will accept minimum constraints from the pre-dispatch calculation engine to avoid situations where the resource may continue to be dispatched below its pre-dispatch schedules forcing the resource to meet the entire min DEL requirement at the end of the dispatch day. OPG recommends the real time engine must also accept minimum constraints from the pre-dispatch calculation engine for the minimum hourly output, maximum number of starts per day and linked resources, time lag and MWh ratio parameters to avoid hydroelectric resources from entering into a SEAL condition in real time. Further rationale is provided in Comments #43 and #44 below.

Section 3.7.2.2 Hydro Parameters

Detailed Comment: Hydro spill cannot be assumed to be dispatchable

The design states that the minimum hourly output (MHO) parameter is to be used when spill conditions are expected to prevent the generating unit from responding to dispatch instructions between 0 MW and the MHO. The DAM and PD calculation engine will use this parameter when scheduling a resource but in RT, if market participants expect spill restrictions to persist in the actual dispatch hour, they can submit an hourly must run value or enter an outage slip in advance of the dispatch hour. If spill restrictions develop during the actual dispatch hour, market participants can request a minimum generation constraint or enter an outage for the remainder of the dispatch hour.

The design seems to imply that dispatchable hydroelectric generation facilities must be capable of responding to 5-minute dispatch instructions and can spill as a normal course of action. Hydroelectric operators may be able to make decisions about sluicegate operation on an hourly basis on select river systems but not every 5 minutes. Sluicegates were not designed to be dispatchable and should not be considered a tool to facilitate dispatch instructions on 5-minute intervals.

OPG suggests a minimum constraint to the MHO or a maximum constraint to 0 MW is entered into the RT calculation engine if the pre-dispatch calculation engine schedules a resource for a MW quantity greater than or equal to its MHO in the PD-2 evaluation. This will reduce the number of outage slips entered and phone calls required in RT. Refer to OPG Comment #10 from Offers, Bids and Data Input Detailed Design.

Detailed Comment: Linked resource, time lag and MW ratio parameter needs to transfer to RT

The design states:

"Upstream and downstream resources can be dispatched for energy quantities that vary from their DAM and PD schedules. Dispatch instructions in the real-time market provide an opportunity for upstream and downstream resources to respond to intra-hour prices signals as long as those dispatch instructions fall within the dispatchable range of the generation units."

The linked resources, time lag and MWh ratio parameters are parameters used to manage the intertemporal dependencies of cascade hydroelectric facilities. If linked resources are not considered in real-time, there is an increased risk of having an "unbalanced" river system and market participants will be required to request IESO to constrain units on or force generation out to manage real time operating constraints that will cause market inefficiencies.

OPG proposes logic that will transfer pre-dispatch schedules to real-time calculation engine in the form of minimum constraints to maintain balance on a cascading river system. When considering which pre-dispatch schedule was appropriate, OPG considered that the greatest flexibility would be able to be provided to the market by making the latest decision possible while weighing the need to break a link in PD-1 due to local inflow changes, outages, or other SEAL events. It is proposed that the IESO implement logic, transferring a minimum constraint equivalent to the PD-2 schedule to the real-time calculation engine for the upstream station of the cascade, with corresponding minimum constraints implemented based on the PD-2 schedule of the upstream station to the linked downstream stations. The downstream equivalents should receive minimum constraint schedules in real- time unless the links are broken/removed by the participant. Refer to OPG Comment #16 from Offers, Bids and Data Input Detailed Design.

Section 3.7.2.2 Hydro Parameters

Detailed Comment: New design may require impractical number of outage slip submissions or request for manual constraints to be entered in RT

The design has multiple references that require market participants to either request the IESO enter a minimum generation constraint or submit an outage slip in real time to manage the dynamic changes in head and flow conditions or hydroelectric resources.

"Registered market participants will continue to submit an outage for the RT calculation engine to dispatch a hydroelectric generation unit to 0 MW when they expect the Max DEL to be reached during the dispatch hour."

If spill restrictions develop during the actual dispatch hour, the registered market participant should:

- Request that the IESO apply a minimum generation constraint for the remainder of the dispatch hour a must run condition has developed; or
- Submit an outage request to dispatch the resource to 0MW for the remainder of the dispatch hour if the resource is unavailable."

"If the RT calculation engine exhausts the maximum number of starts per day for a resource during the dispatch hour, the registered market participant must submit a forced outage to inform the RT calculation engine that additional starts are unavailable."

"When must run conditions develop within the dispatch hour, registered market participants will request that the IESO apply a minimum generation constraint to downstream resources."

As stated in comment #42, OPG recommends that the real time engine accept minimum constraints from the pre- dispatch calculation engines to limit the number of minimum generation constraints requested or outage slips entered that can become unmanageable for both market participants and IESO in real time.

Section 3.7.2 Market Timing

Detailed Comment: Failure to meet DA commitment due to transmission outage

If a generator is unable to meet its day-ahead commitment due to a circumstance outside of its control such as an unplanned/forced transmission outage, they should not be held financially responsible for the book-out. The Market Settlements design document states:

"Under certain circumstances, a market participant with a DAM financially binding schedule may incur a financial loss as a result of an IESO control action on energy and operating reserve in real time. When this occurs, the IESO will provide a DAM Balancing Credit (DAM_BC) to cover any operating loss incurred as a result of following dispatch instructions."

The DAM_BC should apply under the above circumstances.

Section 3.7.2.1 Market Timing

Detailed Comment: Ramp to minimum loading point (MLP)

Market participant changes to ramp rates within the mandatory window should not require IESO approval given that they often need to be implemented with very short lead time.

Detailed Comment: De-Commitment when NQS generation facility has two commitments in a dispatch day

In regard to the last paragraph of this section the IESO states:

"If after the first commitment the RT calculation engine determines that the NQS generation unit is economic to remain in-service in real-time, the RT calculation engine will continue to keep it online and not dispatch it below MLP. If the 5-minute dispatches overlap with the MGBDT such that the generation unit will not be able to comply with a future commitment, the IESO will perform a reliability assessment. If there is an immediate reliability need, the IESO will keep the generation unit in-service until the future commitment starts, otherwise it will enforce the PD de-commitment decision and the RT calculation engine will ramp the generation unit down."

Please clarify if market participants will receive a make-whole payment if their continued operation during the bridge period between the two separate commitments is uneconomic.

Section 3.7.2.2 Linked Resources

Detailed Comment: Breakages in linked resources

Linked resources are used to manage the intertemporal cascade dependencies from one pre-dispatch run to the next and should not exclusively be evaluated based on neighbouring stations.

For example, there are three stations on a cascade river:

- Station A, B and C are linked where A is the uppermost station and C is at the end of the cascade.
- Normally the link would be A->B->C.
- However, Station B is on outage and has spill capability to pass water to Station C.
- If B is in the link with ZERO MW, the link A->B->C will be broken.
- A should then link to C (i.e. A->C).
- Station B can pass an adequate amount water from A to C.
- When Station B outage ends, the link should be restored back to A->B->C.

This example highlights the importance of being able to update linkages, time lag and MWh ratio every hour in order to manage outages during the day. OPG may have additional comments regarding breakages in linked resources during the review of the calculation engine detailed design sections. It is important that linked resources on a cascade river system receive a schedule even if one of the stations goes on forced outage.

Section 3.7.2.3 Additional Reporting

Detailed Comment: Pseudo unit (PSU) outage reports and need for similar reports for other technologies

In regards to the last sentence of paragraph 2 under "Outages":

"Registered market participants will have visibility on the impact of a physical unit derate or outage to the corresponding PSU through confidential market participant reports."

OPG requests that the IESO issue confidential outage reports to show capacity after outages prior to DAM and for each pre-dispatch run. This will provide market participants transparency into which outages have been transferred into the IESO engines.

The IESO has also created this additional reporting for pseudo units and recommends this be extended for all technology types as there may be translation/transfer errors in the IESO tools that require market participants to consider during outage and offer submission. This information may become significant as it could be used in MPM reference quantity calculations.

Section 3.8.1.3 Make-whole payments

Detailed Comment: Non-Quick Start (NQS) commitment modifications for reliability and cost recovery

In regards to the following statements from Section 3.8.1.3:

"The IESO will also continue to initiate changes to commitments for reliability. Reasons for altering a commitment include:

- Market participant initiated change to indicate a later MLP time due to unanticipated equipment failures;
- Market participant initiated withdrawal of a commitment due to equipment failures;
- Market participant initiated change to MLP or MGBRT due to SEAL concerns; and
- IESO initiated withdrawal, delay, advancement or extension of a commitment for reliability."

There should be a mechanism that allows market participants to recover their costs incurred from these changes including costs such as fuel transport & storage.

Section 3.8.4 Hydro Parameter

Detailed Comment: ORA Linked Resources

In regards to the sentence of section 3.8.4:

"During operating reserve activation, the IESO will only schedule additional reserve up to the 10-min reserve requirement as permitted by reliability standards."

Does IESO still respect the MW ratio if the resource is linked to other resources via the linked resource, time lag and MW ratio parameter? For example, if Resource A and Resource B are linked with a time lag of 1 hour and the MW ratio is 1:1. And at 10:15, Resource A receives operating reserve activation (ORA) of 20 MW. Would Resource B receive extra 20 MW of dispatch at 11:15? OPG is seeking clarity on how ORAs will be modelled for Linked Resources.

Section 3.8.5 Market Timing

Detailed Comment: Manual procurement of operating reserve

In section 3.8.5, the design states:

"On a reasonable effort basis, the IESO will attempt to procure operating reserve in amounts that are proportional with each market participant's share in the total available operating reserve capacity. This process will remain the same in the future market."

The IESO should provide a time interval for the manual procurement of operating reserve and details of how this will be settled. The OR should be scheduled on a 5-minute resolution and manually input into IESO tools to allow settlement.

Section 3.8.6 Operating Reserve

Detailed Comment: Detailed OR demand curve

From the November 25, 2019 IESO Stakeholder Engagement regarding Constraint Violation Pricing, the IESO identified that operating reserve demand curves (ORDCs) will be introduced to determine settlement prices.

The ORDC was not mentioned in the detailed design and OPG requests more details regarding the new design element introduced.

Section 3.8.7 Additional Reporting

Detailed Comment: Communication of Control Actions for ACE Excursions

Given the IESO will continue to manually intervene to respond to area control error (ACE) excursions, how will these interventions be communicated to market participants in a way that provides transparency?

This is particularly important in the new market as it could impact a market participants financially binding day- ahead commitments, the eligibility for make-whole payments, and subject the market participant to further impact testing for make-whole payments.

Section 3.8.9 Trading/Interties

Detailed Comment: Clarification on Off-Market Transactions

Section 3.8.9 states that off-market transaction will not be scheduled by the DA and PD calculation engines. OPG is seeking clarification on how this applies to segregated mode of operation (SMO).

Detailed Comment: Off-market transactions

IESO should publish a report providing the details on flows for off-market transactions. This would make it easier for market participants to balance load equations in Ontario, which can be challenging given lack of details on off- market transactions.

Section 3.8.9.3 Trading/Interties

Detailed Comment: Restrictive Timelines for SMO Requests

The detailed design states:

"In the future market, for SMO that requires an outage to a critical transmission element:

- Requests to segregate must be submitted by 08:00 EPT for the following dispatch day. This will provide the IESO with sufficient time to assess the SMO request for reliability and publish associated transmission limit changes; and
- SMO requests can only be cancelled by the generator to address concerns related to the safety of any person, damage to equipment, or violation of any applicable law (SEAL)."

Under the current market, market participants can submit these requests up to two hours prior to the dispatch hour. The new restriction is prohibitive and limits the flexibility to operate in segregated mode in the new market. OPG recommends that current market timelines for SMO requests are maintained in the new market. Generators who wish to be scheduled in SMO in the day ahead market should be subject to normal DAM timelines (i.e. 10:00 EPT rather than 09:00 EPT).

In addition, market participants with direct connection to an uncompetitive intertie (i.e. HQ) should be allowed to engage in SMO for reasons other than SEAL.

Section 3.8.10 Provide Details

Detailed Comment: Details on additional emergency operating state control actions (EOSCA)

The second paragraph of this section states:

"Additional emergency control actions related to changes introduced in the future market will be identified and added to the EOSCA list at appropriate locations. One new emergency control action that has been identified is to allow import offers without DAM financially-binding schedules to be evaluated in all hours of the PD look-ahead period."

The design should include more details and clarity on what additional control actions may be introduced in the new market.

Section 3.9.1.2 Additional Reporting

Detailed Comment: Reporting of incremental imports in PD following DAM failure

In regards to the last sentence of Section 3.9.1.2:

"if the IESO identifies adequacy concerns in future hours, the IESO may elect to include incremental imports in the PD evaluation for all remaining hours of the day for system reliability."

To ensure transparency in the new market, there should be a procedure/mechanism to notify market participants when the IESO includes incremental imports in the PD for system reliability.

Section 3.9.2 Trading/Interties

Detailed Comment: Pre-dispatch remediation

In regards to the final two paragraphs in this section:

"However, if PD fails for two hours or more, the IESO will only be able to implement the DAM intertie transaction schedules that align with transactions present in neighbouring jurisdictions for the RT intertie checkout. No new incremental transactions that are scheduled in neighbouring control areas will be included in RT."

Under this situation, the last available PD schedule should be used for interties rather than the DAM intertie transactions schedule because the data from the last PD run will be more current.

Section 3.9.3.3 Provide Details

Detailed Comment: Electrical islands & real-time Failures

In order to provide transparency and allow for Market Participants to better plan for situations when forced into an electrical island, would the IESO please provide additional details regarding calculation of LMPs in an electrical island including:

- The administrative pricing method (from Table 3-2) to will be used to calculate LMPs in an electrical island.
- The methodology to be used will be applied to calculate LMPs for electrical islands created by forced outages.
- The methodology used will be applied to calculate LMPs for electrical islands created by planned outages.

Providing the methodology will provide transparency and allow for Market Participants to better plan for these situations or develop operational instructions of how to respond if planned/forced into electrical island.