MRP Energy Detailed Design

Design Document: OFFERS, BIDS AND DATA INPUTS

Stakeholder Feedback Form

Date Submitted: 2020/*07/24* **Feedback Due**: July 24, 2020	**Feedback provided by:** Company Name: Ontario Power Generation Contact Name: Greg Schabas Phone: [redacted] Email: [redacted]

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.](mailto:engagement@ieso.ca)

Please let us know if you have any questions.

IESO Engagement

General feedback on the Detailed Design Document (please expand this section if required)
OPG's detailed review comments for the Offers, Bids & Data Inputs 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 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: a) Regarding the joint optimization of energy and operating reserve (OR) in the detailed design documents for the calculation engines, OPG previously proposed a new 'ENERGY + OR Limit' parameter to improve joint-optimization and avoid over-scheduling of operating reserve in the day ahead timeframe for hydroelectric resources. OPG has communicated this proposal to the IESO in past written feedback but has received no formal response from the IESO. We would be happy to discuss this proposal further and provide clarification as needed. b) Overall, there is not enough detail in the design to determine if the new hydroelectric parameters will be an effective replacement for the day ahead commitment process (DACP) resubmission window. Further, these parameters may need to be adjusted as other elements of the design are finalized. OPG's detailed comments on Section 3.4.2 include suggestions on how to improve the design of these parameters. c) The design states that some of the new hydroelectric parameters can only be used to adhere to safety, equipment limitations and applicable law (SEAL) restrictions. OPG proposes the use of the hydroelectric parameters be re-written to allow for physical/operational constraints similar to the IESO treatment of NQS unit parameters (e.g. minimum load point). OPG emphasizes the new hydroelectric parameters were intended to assist hydroelectric operators to avoid infeasible schedules in the day-ahead and pre-dispatch timeframes. d) Changes to the hydroelectric parameters are also necessary within the day as water conditions change during the day. Market participants require the flexibility to switch the hydroelectric parameters on and off and the ability to change them in the day ahead and pre-dispatch timeframes to reflect the physical/operating constraints of their resources. If the market participant elects to use the new hydroelectric parameters in these timeframes, their evaluation must also be extended to the real-time calculation engine. The detailed comments provided include suggestions on how these parameters should be applied in the real-time calculation engine. In summary, to avoid reliance solely on offers which will have an impact on market prices, these physical/operational constraints should be included in the dispatch algorithm and market participants should have the option to use and change the parameters as applicable in all timeframes (i.e. day-ahead, pre-dispatch and real time).

#	Section	Theme	Comment Name	Detailed Comment
1.	**General Comment**	Integration	**Offers Bids & Data Inputs need review in conjunction with calculation engine design**	Review of offers, bids and data inputs in the new market needs to be done in tandem with the review of the calculation engine detailed design documents. The IESO's response to the Publishing & Reporting Detailed Design comments indicates market participants will be given a second opportunity for comments for the Offers, Bids & Data Inputs Detailed Design following the release/review of the calculation engine design documents. OPG further suggests the IESO augments these comments with stakeholder sessions for market participants to discuss their recommendations and/or proposals with each other and the IESO.

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2.	**General Comment**	Additional Engagements	**Need for meeting between hydroelectric market participants and calculation engine vendor**	The IESO should arrange a technical stakeholder session with the calculation engine vendor (ABB) and hydroelectric market participants to discuss the complexities of hydroelectric modelling in the Ontario market. Ontario is unique from other jurisdictions given the uniqueness of its hydroelectric fleet and the calculation engine design requires made in Ontario solutions that use existing resources to their full extent.
3.	**General Comment**	Hydro Parameters	**Proposal to enhance Joint Optimization of Energy and OR**	In OPG's review letter following the January 23, 2020 IESO stakeholder session on Physical Withholding, OPG provided a comment pertaining to the importance of joint optimization of energy and OR for hydroelectric facilities. OPG has reproduced the comment below and stresses that it is important for the IESO to consider this approach or an alternative that achieves the same outcome. Without enhancements to joint-optimization, there is a high risk that hydroelectric resources will receive OR schedules in the DAM that they will not be able to physically achieve in real-time. Without enhanced joint optimization of energy and OR, infeasible day-ahead OR schedules create inefficient market outcomes. , for example: • Resource A receives a 100 MW infeasible day-ahead OR schedule in HE12 for $1 • Resource B offers 100 MW day-ahead OR @ $2 in HE12 – does not receive a schedule. • Resource A provides 0 MW real-time OR in HE12 – buyback of 100 MW at $3 • Resource B provides 100 MW real-time OR for HE12 at $3 reflecting higher opportunity cost in RT than DA. Resource A should not have been scheduled in the day-ahead market and forced to buy back in real-time as this creates an inefficient schedule/market. OPG noted in the July 8th, 2020 meeting between IESO and the Ontario Waterpower Association (OWA), the IESO alluded to changes to the calculation engines that may reduce or mitigate this concern. OPG appreciates the IESO has acknowledged the issue and is intending to identify the solution in the calculation engine detailed design. We look forward to discussing this solution with the IESO and other market participants. ***"Comment #4: Proposal for new "Energy plus OR Limit" parameter to improve Joint-optimization of Energy and Operating Reserve*** *Energy and operating reserve (OR) have different market rules which impact how they are offered. For OR, a resource must be able to provide the energy activated by the operating reserve activation (ORA) for one hour. Along with the hydroelectric capability changes highlighted in Comment #1[1], hydroelectric resources also need to*

[1]Comment #1 from the OPG's review letter following the January 23, 2020 IESO stakeholder session on Physical Withholding was titled: "***Comment #1:*** ***Challenge with Establishing Physical Withholding Reference Levels for Hydroelectric Energy Offers".*** This comment is also reproduced including in OPG's review comments on the Market Power Mitigation Detailed Design (see Comment #9 from Market Power Mitigation comments).

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				constantly evaluate whether they can provide OR for one hour. This uncertainty may lead to fluctuating OR quantities offered during different times of the day based on operating conditions. *For example, energy/OR offers early in the day may have to be reduced to ensure sufficient water remains available such that later energy/OR offers can remain above reference levels. If market participants are constrained in their offers in order to be physically compliant with the market rules, the result could be reduced system efficiency, higher OR prices, and higher overall cost to ratepayers.* *To improve OR scheduling efficiency and reduce the risk of infeasible schedules, OPG proposes a new parameter term, "Energy + OR Limit", which specifies the maximum combined quantity of energy plus OR that can be sustained for one hour given water constraints. This new parameter would be particularly beneficial in the day ahead timeframe to reduce the likelihood of an infeasible schedule. An example of how this new parameter would affect joint optimization is shown in **Appendix A**."* The example is reproduced below in comment titled "Example of Proposed "Energy + OR Limit" Parameter (i.e. Appendix A). OPG is currently participating in stakeholder sessions with the IESO related to "Improving Accessibility of Operating Reserve". OPG has raised this proposed parameter with the IESO Stakeholder Engagement team, and they suggested the parameter be raised again through Market Renewal, as any additional tool changes would be out of scope for their project. OPG also recommended that the IESO track actual dispatch rather than scheduled dispatch when issuing OR Activations (ORAs) in order for participants to meet their ORAs and be able to utilize their compliance deadband fully.
4.	**General Comment**	Hydro Parameters	**Example of Proposed "Energy + OR Limit" Parameter (i.e. Appendix A)**	**The Issue**: The quantity a resource can achieve and sustain in an ORA is contingent on the current energy dispatch which fluctuates based on energy price and the actual output which may differ due to different reasons such as a compliance deadband. There is no parameter to limit the total amount dispatched for energy and scheduled for OR. **Example:** • Energy offer: 60 MW @$20, 70 MW @$40, 100 MW @ $100 • 10S OR offer: 10 MW @ $0.20, 70 MW@$100 (Note the 100 MW lamination is not offered) Only 10 MW of OR offered to coincide with energy dispatch of 60 MW based on Predispatch schedules – 70 MW is achievable for 1 hour. 100 MW is only achievable for 15 minutes. **Scenario 1: Pre-dispatch equals MCP at $25** • MCP $25 and OR Price $1

#	Section	Theme	Comment Name	Detailed Comment
				• Energy Dispatch: 60 MW • OR Schedule: 10 MW • ORA to 70 MW <u>Outcome:</u> Resource ramps to 70 MW in less than 10 minutes and remains at 70 MW for one hour. **<u>Scenario 2:</u>** Pre-dispatch Energy at $25. Market participant expects same outcome as Scenario 1 except MCP increases to $50 • MCP $50 and OR Price $1 • Energy Dispatch: 70 MW • OR Schedule: 10 MW • ORA to 80 MW <u>Outcome:</u> Resource ramps to 80 MW in less than 10 minutes. After 25 minutes the resource derates to 70 MW for water control. It FAILS the ORA since it was not able to provide one hour of OR. An example of the implementation of the proposed solution which reflects actual OR capability for 1 hour is outlined below: **<u>Example (as above):</u>** • Energy offer: 60 MW @$20, 70 MW @$40, 100 MW @$100 • 10S OR offer: 10 MW @ $0.20, 70 MW @$100 • Energy + OR limit: 70 MW **<u>Scenario 3:</u>** Scenario 2 with a new parameter "Energy + OR Limit" of 70 MW • MCP $50 and OR Price $1 • Energy Dispatch: 70 MW • OR Schedule: 0 MW <u>Outcome:</u> No ORA and no issue with non-compliance.

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5.	**General**	Hydro Parameters	**Need more details to assess overall effectiveness of new hydro parameters.**	There are insufficient details in the design document to determine if the new hydro parameters will be effective. Further the design of these parameters may need to be adjusted as other elements of the design are finalized. As examples, the details forthcoming in the calculation engine documents, details on the joint optimization of energy and operating reserve, and how the parameters interact with each other will impact how effective the new hydroelectric parameters are in the day ahead, pre-dispatch, and real-time markets. More detailed analysis will be required by hydroelectric participants and the IESO.
6.	**General**	Energy Storage Resources	**Implementation of storage design criteria**	IESO is currently undertaking initiatives to implement a Storage Design Project (SDP) to allow for Energy Storage Resources (ESRs) to participate fairly within the IESO Administered Market (IAM). During stakeholdering with the Energy Storage Advisory Group (ESAG), it was noted that several design features would be implemented alongside the Market Renewal Project. OPG understands that a decision was made by the IESO to not integrate the long-term SDP with MRP. This decision, although understandable to manage Market Renewal Project scope, will undoubtedly lead to barriers when making necessary changes to ensure appropriate design criteria for ESRs in the future. One significant design criteria for ESRs in the long-term SDP was the implementation of a 'continuous offer curve'. The plan is for energy storage offer curves to be continuous over the charging and discharging range, which reflects the full operating range of the facility. It will implicitly and automatically enforce the no overlap rule already in place under the SDP Interim Design, and eliminates the possibility of simultaneous/infeasible dispatch instructions to charge and discharge. The IESO SDP team has engaged with ABB, the software vendor selected through the Market Renewal – Energy program, to understand its storage solutions and to assess how various design criteria can be implemented (Continuous Offer Curves, SoC Management etc…). The SDP Interim Design has proposed changes to Market Rules and Manuals ahead of MRP implementation, and therefore these design criteria should be factored into or referenced in MRP, particularly in the Offers Bids and Data Inputs Detailed Design.
7.	**2.2.1**	Omission	**Add Bullet on Forbidden Regions**	In Section 2.2.1, the IESO bullets do not include forbidden regions. For additional clarity, OPG suggests the bullet list of new dispatch data features for hydroelectric resources include a bullet describing forbidden regions.
8.	**2.2.2**	Additional Reporting	**Dynamic loss factors may be problematic if updated frequently**	OPG recommends the IESO provide some form of reporting on the impacts of dynamic loss factors to price & dispatch in order to provide transparency to market participants. As per previous comments submitted by OPG on the high level design, OPG remains concerned over the decision to adopt dynamic loss factors given the challenges that arose when they were first implemented at market opening in 2002 (see OPG's previous comments on the Single Schedule Market high level design). OPG has reproduced its previous comment on the Single Schedule Market (SSM) high level design regarding dynamic loss factors below: *"**2.3.2 Energy Price – Loss Component***

#	Section	Theme	Comment Name	Detailed Comment

				"The IESO has also determined that dynamic loss factors will be used, where technically feasible, to more accurately calculate losses."
				
				• *In general, OPG does not support dynamic loss factors updated more frequently than one hour, due to experienced dispatch volatility issues experienced when it was last implemented at market open (2002). The IESO acknowledges these issues and states quasi-dynamic loss factors will be considered if using dynamic loss factors is not technically feasible.*
				    ○ *Is the IESO suggesting possible different loss factor frequency updates by node?*
				    ○ *In OPG's experience, it is not possible to accurately determine whether dispatch volatility will be an issue until the system is live. How does the IESO intend to determine if dispatch volatility will be an issue and if so, how quickly will it be able to adjust its methodology if needed?*
				    ○ *It is important for OPG to always have the most updated penalty factors. If penalty factors are updated more frequently than hourly, it will be challenging to optimize dispatch at energy limited resources to benefit the customer."*

9.	**3.4.2**	Hydro Parameters	**Impact of changes to design of hydroelectric parameters since high level design**	During the high level design, the IESO made a series of detailed design decisions that impacted hydroelectric resources. The IESO documented some of the concerns/trade-offs on Page 62 of the Day Ahead Market (DAM) high level design as follows: *"The IESO identified the need to remove the current DACP resubmission window which hydroelectric resources use to increase the likelihood of receiving a feasible day-ahead schedule. While the resubmission window works well under the DACP, it could give hydroelectric resources an unfair advantage over other resources under a DAM. In lieu of a resubmission window in DAM, the IESO began discussing potential software requirements in the optimization engine to model hydroelectric resources. Stakeholders showed particular interest in how the IESO would determine the needed requirements and asked to be included in this development. Stakeholders also asserted that the IESO develop these requirements during the HLD rather than the detailed design phase. Stakeholder feedback received from this meeting was used by the IESO to develop software requirements that will be included in the vendor RFP."* Hydroelectric stakeholders participated in discussions with IESO which resulted in the inclusion of Section 3.4 *"Optimization of Hydroelectric Resources"*. The IESO defined the issues in DAM high level design, Page 32: *"Hydroelectric resources have many unique operating characteristics that impact the amount of energy and operating reserve they are able to produce. Some relate to physical equipment limitations, while others are determined by regulatory and environmental requirements related to public safety and fish spawning. Operating characteristics common to most hydroelectric resources include minimum output requirements, limited start-up cycles, daily energy limits and scheduling dependencies with adjacent upstream or downstream resources on the*

#	Section	Theme	Comment Name	Detailed Comment
				same river system. Hydroelectric resources can be infeasibly and inefficiently scheduled in an energy market if these operating characteristics are not respected by energy market software. The risk of receiving an infeasible schedule would reduce a hydroelectric resource's willingness to participate in a financially binding DAM. This is because an infeasible DAM schedule would not accurately reflect what the resource is actually capable of delivering in the RTM. A financially binding DAM schedule that is incapable of being delivered in the RTM places the market participant at an increased risk of having to buy out of its DAM schedule at a loss. Infeasible DAM schedules would therefore decrease the efficiency of the DAM because hydroelectric resources would be less encouraged to participate in the DAM. This presents a significant risk to the efficiency of the Ontario DAM considering hydroelectric resources represent nearly one-quarter of Ontario's available capacity." Whereas we generally support the IESO's high level design views, it does not appear that these concepts have been transferred effectively into the detailed design. Since the publication of the high level design, it appears the IESO revised the design to the following: • Use of Availability Declaration Envelope (ADE) conditions similar to today's DACP to solve the participation concern noted in the above text. (NOTE: OPG will include a detailed comment detailing issues with the decision to retain the ADE in its Grid & Market Operations Integration submission) • Limit the use of hydroelectric parameters to situations where a safety, equipment, or applicable law (SEAL) constraint exists. This restriction prevents these parameters from being used to help create feasible day-ahead and pre-dispatch schedules when water conditions change during the day. Based on these changes, OPG no longer expects day-ahead and real-time schedules to converge and the expectation is that divergence will occur in real-time leaving market participants to manage the uncertainty and buyback risk between the two markets with only offers. The above IESO decisions have decreased the certainty and transparency of day-ahead and real-time schedules, which will require market participants to self manage hydroelectric resources in both day-ahead and real-time schedules through: • hourly offers dependent on passing Market Power Mitigation reference level and quantity assessments, • new hydroelectric dispatch data parameters (changes restricted to SEAL only), and • reliance on real-time must run constraints instead of using good utility practice/proactive approaches for managing physical and operational considerations.

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10.	**3.4.2**	Hydro Parameters	**Clarification on use of hydroelectric parameters**	On July 8th, 2020 during a conference call with the Ontario Waterpower Association (OWA) and IESO, it was OPG's impression the IESO was not aware the specific language around SEAL prevents the full use of hydroelectric parameters by Market Participants in day ahead and pre dispatch timeframes. At this meeting the IESO suggested that OPG and the OWA should bring forward recommendations to redefine the terminology used for the new hydroelectric parameters. OPG is recommending similar language as used for Non-Quick Start (NQS) resources (i.e. MLP, MGBRT, MDT, Lead time). The main purpose in having and utilizing the hydroelectric parameters is to avoid running into SEAL restrictions, which would ultimately reduce the flexibility of hydroelectric resources in the market. OPG reiterates that hydroelectric stations have physical operating constraints in day ahead, but do not always have SEAL concerns until closer to real-time. An example of a SEAL constraint in day ahead would be an instantaneous flow requirement required by a water management plan – this is a known requirement in day ahead and fits the SEAL definition. A peaking cascade station may not have a SEAL limitation until there is an imminent schedule for upstream/downstream stations or inflows have risen requiring the station to generate. In the day ahead timeframe, cascade stations have the flexibility to generate in almost any hour of the day. It is only when water is in motion that SEAL constraints are known – these become more apparent as it gets closer to real time operation. As part of good utility practices, hydroelectric operators take actions to proactively manage generation to avoid imminent SEAL events. It can be a difficult "juggling act" to operate within the many rules and requirements of the IESO market without invoking SEAL. OPG recommends the IESO rewrite the sections relating to the new hydroelectric parameters to allow them to be used for physical/operational constraints as well as SEAL. This comment also applies to the Grid & Market Operations Design Document. It is OPG's interpretation that NQS resources are similar to hydroelectric cascades in that they have physical/operational constraints that need to be modelled in day-ahead and pre-dispatch – these can also become SEAL constraints in real time. OPG is seeking the same treatment for hydroelectric stations as provided for NQS resources. If the IESO is eliminating the resubmission window due to unfair treatment across all technologies, it should avoid creating another situation where hydroelectric facilities are disadvantaged. During OPG's review of the detailed design documents the definitions for minimum load point (MLP), minimum generation block run time (MGBRT) and minimum down time (MDT) did not have SEAL requirements associated with them. The IESO's definitions of MLP, MGBRT, and MDT on Page 31-33 are: • *"Minimum loading point (MLP) will continue to represent the minimum MW output that a generation unit must maintain to remain stable without the support of ignition."*

#	Section	Theme	Comment Name	Detailed Comment
				• *"The minimum generation block run-time (MGBRT) parameter will continue to represent the minimum number of consecutive hours a generation unit must be scheduled to its MLP."* • *"The minimum generation block down time (MGBDT) parameter will continue to be defined as the minimum number of hours between the time when a generation unit was last at its MLP before desynchronization and the time the generation unit can be scheduled back to its MLP after resynchronizing."* As part of our review of this detailed design document, OPG has proposed alternative solutions with rationale to the IESO. These are listed by parameter in Section 3.4.2.
11.	**3.4.2**	Hydro Parameters	**Alternative wording for Minimum Hourly Output (MHO)**	The Minimum Hourly Output (MHO) parameter is a new hourly dispatch data parameter introduced to allow market participants to specify minimum generation requirements. If economic, it is the minimum amount of energy that must be produced in any one hour. From a principal perspective, OPG proposes the MHO parameter should be designed to: • Be used in day-ahead, pre-dispatch, and real-time calculation to reflect physical/operating constraints related to sluice gate operation and subsequent water management requirements. • Provide a feasible day ahead schedule that has evaluated MHO. • In the pre-dispatch calculation engine evaluate the submitted MHO amount in terms of whether a hydroelectric station is scheduled above the MHO. The pre-dispatch calculation will evaluate for constraints and perform joint optimization of energy and operating reserve, as such, it is possible for a system constraint to cause a resource to be scheduled above its economic operating point in pre-dispatch. • In the real-time calculation engine, if the pre-dispatch calculation engine evaluates and schedules a resource for a MW quantity that is greater than or equal to its MHO, apply a minimum constraint to the MHO or a maximum constraint to 0 MW. OPG proposes the pre-dispatch schedule used for evaluation is PD-2, this would allow time for proactive sluicegate changes based on the expected real-time dispatch. • Allow hydroelectric operators to make decisions about sluicegate operation on an hourly basis instead of 5 minute basis. Sluicegates were not designed to be dispatchable and should not be considered a tool to facilitate dispatch instructions. • Reduce the number of dispatches to stations with physical/operating constraints related to sluice gate operation. • Reduce wear and tear on sluicegates preventing equipment damage. • Allow energy and operating reserve flexibility and dispatch above the MHO amount. Based on the above principles, the following alternative wording to the MHO parameter is proposed:

#	Section	Theme	Comment Name	Detailed Comment
				"Minimum hourly output will be a new optional hourly dispatch data parameter used to represent the minimum amount of energy, in MWh, that a generation unit associated with a dispatchable hydroelectric generation facility either generates, or forgoes the opportunity to generate, depending on the day-ahead and pre-dispatch calculation engine evaluations. A default value of 0 MWh will be used if a minimum hourly output is not submitted. *Based on the PD-2 schedule produced by the pre-dispatch calculation engine, if the PD-2 schedule is greater than the MHO submitted then a minimum constraint to the MHO value will be transferred to the real-time calculation engine or a maximum constraint of 0 in the corresponding real-time hour. If a MHO minimum constraint is transferred to the real-time calculation engine, the generation unit will remain fully dispatchable above the minimum hourly output value.* *Registered market participants will only be eligible to submit minimum hourly output quantities for generation units associated with a dispatchable hydroelectric generation facility. A minimum hourly output value can be submitted if:* • *spill restrictions are anticipated to prevent the generation unit from responding to dispatch instructions between 0 MW and the minimum hourly output value; or* • *following a dispatch instruction between 0 MW and the minimum hourly output value the registered facility is unable to follow the dispatch instruction as its operation may endanger the safety of any person, damage equipment, or violate any applicable law.* *The following criteria should also apply:* • *Minimum hourly output quantities submitted as dispatch data shall not exceed the maximum quantity of the energy offer for the generation unit; and* • *Sum of all hourly must-run quantities submitted as dispatch data must be less than or equal to the maximum daily energy limit submitted as dispatch data for the generation unit."*
12.	**3.4.2**	Hydro Parameters	**Alternative wording for Forbidden Regions**	Similarly from a foundational principle perspective, it is proposed that the forbidden region parameter be designed for use in day-ahead, pre-dispatch, and real-time calculation engines to: • Create feasible schedules representing the operating ranges of hydroelectric units. • Model an increased number of forbidden regions. In the current market there are only three forbidden regions per resource aggregate. OPG proposes this is expanded to at least 8. This would reflect the number of hydroelectric units per resource aggregate, OPG has one resource aggregate containing 8 units and multiple resource aggregates containing 3 or 4 units. • Allow changes based on operating conditions/head and the best efficiency point for operations.

#	Section	Theme	Comment Name	Detailed Comment
				For example: • A resource aggregate with two units, each unit has an unsteady operation range between 0% to 40% wicket gate positions. The equivalent MW to the 40% wicket gate position will vary based on hydroelectric head based calculation, and the number of units available and expected to generate at a station. Specifically, inflows, headwater levels, discharges, and tail water levels are some of the parameters in the hourly calculations of efficiency and capacity. • At normal head, 40% gate is approximately 50 MW and capacity is 70 MW. • This results in Unit 1 (U1) forbidden range of 0 MW to 50 MW for the first unit, with efficiency point 55 MW. • U1 is dispatchable between 50 MW and 70 MW. A Market Participant needs to use their U1 forecast dispatch to calculate and submit the forbidden region that reflects U2 forbidden region. • If the Market Participant expects the U1 to be dispatched at 50 MW, then the second forbidden range submitted would be 70 MW to 100 MW. • If the Market Participant expects U1 to be dispatched to 70 MW, then the second forbidden range submitted would be 70 MW to 120 MW. • OPG proposes the IESO extend the use of forbidden regions to model both operating restrictions and unit efficiency outputs. This would allow U1 forbidden region to be submitted at 0 MW to 55 MW (efficiency point) and U2 forbidden region to be submitted as 70 MW to 110 MW (based on expectation that U1 is dispatched to either 0 MW or 55 MW). • Further rationale for using unit efficiency in forbidden zone relates to the calculation of daily energy limits. Based on the above rationale, the following alternate wording for Forbidden Regions is proposed: *"Forbidden regions will be a new voluntary daily dispatch data parameter used to represent one or more operating ranges, in MW, within which a hydroelectric generation unit has operational limitations that may cause equipment damage. This includes submission of forbidden regions based on forecast dispatch of each unit and may include operational efficiency points. Registered market participants will only be permitted to submit forbidden region quantities for generation units associated with a dispatchable hydroelectric generation facility that is registered to submit this dispatch data parameter during the Facility Registration process. The number of forbidden regions will be increased to allow each unit on a resource aggregate to model at least one forbidden range."*
13.	**3.4.2**	Hydro Parameters	**Alternative wording for Minimum Daily Energy Limit (Min DEL)**	The parameters MIN DEL and MAX DEL are MWh amounts. Water management plans do not deal with MWh - they deal with volumes of water over a day. ○ A translation from volumetric to energy requires an assumption of an operating point, which is usually assumed to be a unit's efficiency point for future based calculations.

#	Section	Theme	Comment Name	Detailed Comment
				○ During day ahead, assuming the same physical characteristics as in the Forbidden Regions example from Comment #12, scheduling a unit to 50 MW which is below its efficiency point of 55 MW will use more water than expected during MIN/MAX DEL submissions. ○ During pre-dispatch and real-time, the DEL is evaluated hourly based on actual discharges (not MWh), inflows, operating limits, a correction for IESO inferred actual DEL usage based on MWh (not flow), and a forward looking calculation of remaining MIN and MAX DEL amounts. ○ Due to the above, DEL calculations require provisions to be updated on an hourly basis and are most accurate when units operate at their best efficiency points. Incorporating the above fundamental principles, the following alternate wording for Minimum Daily Energy Limit (Min DEL) is proposed: *"Min DEL will be a new voluntary dispatch data parameter that represents the minimum amount of energy, in MWh, that a generation unit must be scheduled to supply within a dispatch day to prevent the registered facility from operating in a manner that could endanger the safety of any person, damage equipment, or violate any applicable law. This parameter will be used by day-ahead, pre-dispatch, and real-time calculation engines. (See Grid & Market Operations Integration for details on application to RT calculation engine.)* *This parameter will only be available to registered market participants submitting dispatch data for generation units registered with a dispatchable hydroelectric generation facility. A Min DEL value can only be submitted for anticipated daily must-run conditions required to prevent the registered facility from operating in a manner that may endanger the safety of any person, damage equipment, or violate any applicable law."*
14.	**3.4.2**	Hydro Parameters	**Requirement for multiple Daily Energy Limits**	To expand upon the above rationale for DEL calculation, inefficient scheduling either above or below the unit's best efficiency point will impact accuracy of Max DEL calculation and may ultimately cause infeasible day ahead schedules allowing scheduling of generation that is at a higher opportunity cost. Although, multiple DELs were part of the DAM high level design, the detailed design does not allow market participants to submit multiple DELs to represent quantities of energy with different opportunity costs. In the DAM high level design (Page 34), the IESO stated: "*Environmental and regulatory conditions can limit the amount of water a hydroelectric resource can use to produce energy over the course of a day. The value of this limited hydroelectric energy is based on the principle of opportunity cost, the value of using limited water to produce energy at a particular time at a given price or saving it for future use at higher prices. Often, a hydro resource's daily energy limit can consist of multiple quantities of water with different opportunity costs. Quantities of water that must be used in the short term (e.g., run-of-river water) will have a relatively lower opportunity cost compared to water that can be stored in a forebay for future*

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				use at times of potentially higher prices. Enabling multiple DELs to represent quantities of energy with different opportunity costs should result in a more accurate representation of costs and improved resource optimization within the DAM and pre-dispatch engines." OPG proposes the IESO reinstate the DAM high level design decision to enable multiple DELs to represent quantities of energy with different opportunity costs in the day ahead calculation engine. The ability to revise offers and MIN/MAX DEL during dispatch days as conditions change lessens the need for multiple DELs in the pre-dispatch calculation engine.
15.	**3.4.2**	Hydro Parameters	**Maximum Number of Starts per Day (MNSPD)**	In the DAM high level design Page 34, the IESO recognized that: "*Hydroelectric resources are capable of quickly responding to dispatches but are at risk of becoming unavailable when the number of up and down dispatches from an energy quantity of zero exceeds pre-defined thresholds that are imposed to prevent equipment failure. The number of up and down dispatches can be minimized by controlling the number of times a resource is started. Not respecting these constraints in the DAM and pre-dispatch engines places a hydroelectric resource at risk of not being able to meet schedules generated once the pre-defined thresholds are exceeded.* " OPG appreciates that in the future both the day-ahead and pre-dispatch calculation engines will use the Maximum Number of Starts per Day (MNSPD) parameter. However, without addressing the wear and tear caused by unit starts and stops in real-time by respecting the MNSPD parameter, there will be an increased risk of equipment damage and resultant outages if the pre-defined thresholds are exceeded. In order to mitigate this situation, the market participant will need to submit an outage in real-time once MNSPD is reached which will require the IESO to manage a larger number of outages. **<u>Example:</u>** It is common for some resources to be started at xx:45 and stopped at xx:00 or started xx:05 to xx:15 on an hourly basis to react to changes to interties and primary demand. Without some consideration of a link between pre-dispatch and real-time calculation engines, resources could use up the MNSPD early in the day and face the possibility of being forced out for the remainder of the day. On a cascade river system, the upstream/downstream stations may also be forced out. OPG is concerned this will remove available capacity from later hours (that could be avoided through an improved design) and subsequently create buy back risk between day ahead and real time schedules. OPG proposes the real-time calculation engine considers the use of starts in the current real-time hour vs. saving them for subsequent pre-dispatch hours.

#	Section	Theme	Comment Name	Detailed Comment
				Also, in the event the MNSPD is exceeded for the day and the market participant keeps the unit available, a process should be created that allows market participants to NULL or remove the MNSPD. If this process is not created, pre-dispatch schedules for the remainder of the day will be zero yet the unit remains available for dispatch in real-time. This creates an inefficient market outcome.
16.	**3.4.2**	Hydro Parameters	**Max Number of Starts Per Day Needs to be at Unit Level**	In Section 3.4.2 on Maximum Number of Starts per Day, the design states: *"The maximum number of starts per day (MNSPD) parameter will continue to be defined as the maximum number of times a generation unit can be started within a dispatch day." where the IESO previously defined generation unit as a resource type (resource aggregate/injection point level) which could include multiple generating units. As per OPG's earlier comment, the generation unit terminology confuses how this parameter is applied and requires clarification."* The Facility Registration Section 3.6.1 on Start Indication Value, states: *"The start indication value will be a new optional registration parameter that represents the minimum quantity of energy a resource must be scheduled to determine whether the generation units associated with resource have used up one or more of their maximum number of starts per day. Market participants must provide one or more MW values for each resource that is registered as a dispatchable hydroelectric generation facility. The number of MW values available will be equal to the number of generation units associated with the resource. The values provided must be greater than 0 MW and less than or equal to the maximum active power capability registered for each resource. If no value is provided, the registered market participant will not be permitted to submit maximum number of starts per day as dispatch data. The value for this parameter will be used by the DAM and PD calculation engines to ensure the maximum number of starts per day for the resource submitted as dispatch data by the registered market participant are not exceeded."* OPG recommends the maximum number of starts per day is assessed 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 or another solution that is transparent for Market Participants. 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."*

#	Section	Theme	Comment Name	Detailed Comment
				It is recommended the IESO re-assess the value of 24 starts per day depending on whether MNSPD is at the resource type level or the unit level.
17.	**3.4.2**	Hydro Parameters	**Restricted use of Linked Resources, Time Lag and MWh Ratio**	The language used in the detailed design document, will restrict a market participant's ability to utilize the new hydroelectric dispatch data parameters for cascade rivers in the Day Ahead Market. This limits a hydroelectric station's ability to receive feasible day ahead schedules and increases the buyback risk when operating in real time. OPG proposes the section on Linked Resources, Time Lag, and MWh Ratio on page 27 be rewritten to: *"Linked resources, time lag and MWh ratio will be three new daily dispatch data parameters used to represent the energy production and time lag relationship between generation resources on a hydroelectric cascade river system. The energy produced by upstream resources require a proportional amount of energy to be produced by downstream resources after a period of time to represent the physical/operational constraints of a cascade river system.* *Registered market participants will have the ability to link eligible resources and stations such that all of the hourly energy offers for the upstream resources will be evaluated with all of the hourly energy offers for linked downstream resources.* *Time lag represents the amount of time it takes for the water discharged from the upstream resource to reach a linked downstream resource. Registered market participants would submit a time lag value of zero to indicate that the energy offers for the linked resources must be scheduled in the same dispatch hour. A time lag value of greater than zero would indicate the linked resources must be scheduled with a delay between them.* *MWh ratio represents a proportional amount of energy that must be scheduled at a linked downstream resource for every MWh of energy scheduled at the upstream resource.* *Linked resource, time lag and MWh ratio values can only be submitted to reflect the physical/operational constraints of cascade river systems. The IESO may review the submission of these parameter values to confirm the registered market participant is in compliance with this requirement.* *The DAM and PD calculation engines will evaluate the energy offers for linked resources, and if optimal to do so, schedule linked resources in respect of the time lag and MWh ratios submitted as dispatch data."* In addition to the rewritten section, 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 most flexibility is provided to the market by making the latest decision possible while weighing the need to break a link in PD-1 due to local

#	Section	Theme	Comment Name	Detailed Comment
				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.
18.	**3.4.2**	Hydro Parameters	**Confirm that Linked Resources, Time Lag and MWh Ratio parameter is applied at station level**	In the sub-section describing "Linked Resources, Time Lag and MWh Ratio", the design refers to linkages between **resources** on hydroelectric cascade river systems. The IESO should clarify what exactly is meant by **resources** in the context of Linked Resources, Time Lag and MWh Ratio parameter and whether it refers stations or individual aggregates (or both). It is OPG's understanding that the parameter will be applied at the station level.
19.	**3.4.2**	Hydro Parameters	**Uncertainty regarding Multiple Units on a Hydro Resource**	On page 19, the design states: *"The resource type will continue to be used to identify the type of resource associated with a registered facility which will be used for submission of dispatch data and to validate that the registered market participant is submitting the appropriate dispatch data parameters for the resource type. For dispatchable generation facilities, the resource types will be:* *- Generation unit; or* *- Pseudo-unit."* Hydroelectric generation facilities typically have multiple generation units offered to the market on a resource aggregate/injection point. The IESO use of "Generation unit" as a defined term becomes confusing in subsequent sections and other detailed design documents when hydroelectric facilities have multiple generation units. This makes it increasingly difficult to assess whether dispatch data parameters apply to the resource type level or the generating unit level. For instance, the maximum number of starts per day needs to be defined as either unit level or resource level.
20.	**3.4.2**	Hydro Modelling	**Capability to modify hydroelectric daily dispatch data (DDD) intra-day**	The design indicates that current hydroelectric daily dispatch data can only be revised hourly for the rest of the day due to a SEAL reason. It is recommended that changes to hydroelectric daily dispatch data (from Table 3-1) be allowed with every hourly submission during the day to allow market participants to better reflect changing/evolving physical conditions including: • Linked resources, time lag and MWh ratio • Forbidden regions • Max/Min DEL • Max number of starts per day As hydroelectric conditions change, and unplanned outages and transmission constraints arise, market

#	Section	Theme	Comment Name	Detailed Comment
				participants require the flexibility to modify the daily dispatch data parameters hourly to reflect physical operational restrictions.
21.	**3.4.2**	Pseudo Units	**Use of Pseudo Units for more than Combined-Cycle Gas**	In the absence of the full optimization model for hydroelectric, parameters that have been established for NQS units and in particular the enhanced pseudo unit models could be extended further to include hydroelectric stations. The provisions to avoid over-scheduling pseudo units for operating reserve in the day ahead is of specific interest to OPG, who has been attempting to engage IESO in discussions relating to joint optimization of energy and operating reserve for some time. The parameters created to accommodate pseudo units may also benefit other technologies and the IESO may want to expand pseudo unit's eligibility to other technologies. This ensures that all technologies are treated in a similar manner.
22.	**3.4.2**	Hydro Parameters	**Permission and documentation required for use of Hourly Must Run (2nd paragraph)**	The second paragraph under the "Hourly Must Run" section (page 25) states: *"Registered market participants will only be eligible to submit hourly must-run quantities for generation units associated with a dispatchable hydroelectric generation facility* ***if*** *the IESO permits a maximum hourly must-run quantity to be registered for the generation facility during the Facility Registration process."* The previously provided details in the Facility Registration Detailed Design Document lacked sufficient detail. This document states on Pages 32-33: *"Market participants will be required to prove they have hourly must run conditions by providing technical data or other applicable supporting documentation to support the values registered for each identified resource. The IESO will review the registered data and may request additional technical data to support the values registered. The IESO may deny registration of the hourly must run resources if the IESO determines that the technical data does not support the request. The value must be greater than zero and less than or equal to the maximum generator resource active power capability value registered for the resource."* The IESO should engage Market Participants in technical discussions, workshops, and one-on-one discussions to determine the types of supporting documentation that will be required and develop a review process for this documentation. Depending on the criteria established by IESO for supporting documents, this may be a costly undertaking for Market Participants.
23.	**3.4.2**	Hydro Parameters	**Clarification needed on Hourly Must Run Parameter in Real-time**	There is a discrepancy in Offers Bids and Data Inputs Section 3.4.2 and Grid & Market Operations Integration Section 3.7.2.2 and Section 3.4.2 should be updated to be consistent with Grid & Market Operations Integration Section 3.7.2.2. OPG recommends that Hourly Must Run submissions be respected in the real-time calculation engine. Offers, Bids, and Data Inputs-states: *"Hourly must-run will be used as an input to the DAM and PD calculation engines to schedule a generation unit registered with a dispatchable hydroelectric generation facility to no less than the hourly must-run value for every*

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#	Section	Theme	Comment Name	Detailed Comment
				hour that the value is submitted by the registered market participant." The above statement does not indicate applicability to the real-time calculation engine, however, OPG notes that Section 3.7.2.2 of the Grid Market Operation Integration document states: *"The RT calculation engine will dispatch a hydroelectric generation facility to no less than the hourly must run value submitted for a particular dispatch hour for the duration of that dispatch hour."* This statement suggests that Hourly Must Run does apply to real-time. OPG proposes Section 3.4.2 of Offer Bids and Data Inputs be rewritten as: *"Hourly must-run will be used as an input to the DAM, PD and RT calculation engines to schedule a generation unit registered as a dispatchable hydroelectric generation facility to no less than the hourly must-run value for every hour that the value is submitted by the registered market participant."*
24.	**3.4.2**	NQS	**Need ability to modify MGBDT & Lead Time parameters intra-day**	The design states: *"The PD calculation engine will determine which one of the three MGBDT values to use based on the number of hours the generation unit has been offline. A NQS generation unit will be considered offline by the PD calculation engine if it is scheduled below its MLP value by the PD calculation engine."* Using predefined MGBDT values to determine if Hot/Warm/Cold dispatch data applies for pre-dispatch calculation may not accurately reflect the condition of a plant. The condition of thermal plants can vary start-to-start, and thus modifications to hot, warm and cold lead times may be necessary during the day. The thermal state of a NQS unit is determined by its turbine temperatures and can only be accurately determined by the unit operator. OPG requests the IESO publish an hourly standardized confidential report to indicate the inferred state of the generation unit and suggests that a mechanism or process be put in place that allows modification of the Lead Time parameter for SEAL and operational reasons to ensure the accurate thermal state is reflected in the market.
25.	**3.4.2**	NQS	**Ramp UP Energy to MLP to include different values**	Ramp UP Energy to MLP should allow for units that have multiple ramp up hours to MLP to submit differing values for each RAMP UP hour. For example, HE12 - 20 MW and HE13 - 200 MW should not need to be represented by 110 MW (the average) for each hour. From this example, the use of average causes discrepancies and market inefficiencies in both hours that is avoidable by allowing two separate values. OPG suggests the IESO be explicit that OR will not be scheduled on a resource during the RAMP UP to MLP period.

#	Section	Theme	Comment Name	Detailed Comment
26.	**3.4.2**	NQS	**Market Participant defines what Start Up Offer to use**	Start-up offers will replace start-up costs in the future day ahead and real time market. The design states: *"The DAM calculation engine will use the start-up offer that corresponds to the hot, warm or cold operating state which will be selected by the registered market participant for the purposes of DAM scheduling. The PD calculation engine will evaluate each of the three start-up offers of hot, warm and cold submitted by the registered market participant based on how many hours the resource has been offline as determined by the MGBDT submitted as dispatch data."* Using predefined MGBDT values to determine if Hot/Warm/Cold dispatch data applies for pre-dispatch calculation will not always accurately reflect the condition of a plant. Similar to Comment #22 above, OPG suggests that the Market Participant be allowed to specify in the hourly dispatch data what the thermal state of the unit is for any given hour rather than using the MGBDT parameter to determine its state. For example, consider a NQS unit with the following parameters identified: MGBDT (HOT) = 5 hours; MGBDT (WARM) = 7 HOURS; MGBDT (COLD) = 9 hours. LT (HOT) = 2 hours; LT (WARM) = 4 hours; LT (COLD) = 7 hours The unit is synchronized. The pre-dispatch report identifies that it will be below its MLP in HE10. Under normal circumstances, the unit will be offline within 15 minutes of the dispatch below MLP; i.e. offline by 09:15. However, there are cases where the unit is delayed in coming offline. In this example, let's assume that rather than coming off-line at 9:15, it comes offline at 10:15. The minimum downtime for a unit is specified from breaker open to breaker close. Under normal circumstances, the unit will be evaluated based on a HOT start for HE15 and 16, WARM for HE 17 and 18 and COLD for HE 19 onwards. Because of the delay in getting the unit de-synchronized, the unit should be evaluated based on a HOT start for HE16 and 17, WARM for HE18 and 19 and COLD for HE20 onwards. To ensure correct start-up costs are used, OPG is proposing that market participants are able to specify what the thermal state is for any given hour instead of allowing the MGBDT parameter to infer what the unit status is.
27.	**3.4.3**	AGC	**Automation of AGC Schedule in Future Market**	The current market process of submitting AGC schedules and revisions to the IESO is a manual process that should be better automated during Market Renewal. This automation could 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	Theme	Comment Name	Detailed Comment
28.	**3.4.4**	PRL	**Bid to Consume Energy**	On page 39 discussing Price Responsive Loads (PRL), the design states: *"Registered market participants will continue to have the ability to designate all or a portion of a bid to consume energy for a dispatchable load as non-dispatchable by submitting the maximum market clearing price (MMCP) with the quantity intended to be non-dispatchable."* This is a departure from current market design, where a dispatchable load can declare their entire load as non-dispatchable by: • not having a bid to consume for an hour (i.e. either not submitting an energy bid or withdrawing an existing energy bid) or • by bidding the entire load at MMCP. The IESO's omission of the ability to declare entire load as non-dispatchable by having no bid at the market reduces market participant flexibility and may limit participation in the Day Ahead Market.
29.	**3.4.5**	Trading / Interties	**Three-hour window to incorporate new import/exports offers in pre-dispatch is too late**	If the pre-dispatch calculation engine is modified to only use dispatch data for imports and exports with DAM schedules, reliability may be impacted if the IESO does not schedule enough resources to meet the increased demand if exports outside of the DAM window are not evaluated. Market efficiency may also be impacted if a NQS resource is committed in lieu of a more economic import that would have been scheduled in pre-dispatch. Also, OPG is uncertain if intertie transactions will be sufficiently incented to participate in the DAM. Has the IESO considered additional incentive mechanisms for DAM participation similar to what's used in some U.S. jurisdictions?
30.	**3.4.5**	Trading / Interties	**Evaluation of day ahead import/ exports schedules in pre-dispatch**	In the Boundary Entity Dispatch Data to Import and Export Energy section, the design states: *"The DAM calculation engine will use this dispatch data to economically schedule imports and exports for any given dispatch hour in a dispatch day. However, the PD calculation engine will be modified to only use dispatch data for imports and exports with day-ahead market schedules until the pre-dispatch run three-hours ahead of each dispatch hour."* OPG would like clarification if following the DAM, and if market participants modify their DAM cleared import/export offers/bids earlier than 3 hours ahead of real-time, will the revised offers/bids be used in the pre-dispatch runs? For example, a market participant has an economic offer to export 100 MW to MISO in the DAM in HE14. Due to anticipated conditions in real-time, the market participant has decided to lower their offer price to export in HE8

#	Section	Theme	Comment Name	Detailed Comment
				for HE14 such that they are no longer economic to export the 100 MW; i.e. intentionally booking out of the day-ahead commitment. Will the pre-dispatch runs use the revised offers once they have been entered or will the IESO wait to evaluate them until they fall within the 3-hour ahead timeframe? It is proposed that the pre-dispatch engine should be able to incorporate all revised bid/offer data for DAM cleared imports/exports in all pre-dispatch runs, including those earlier than 3-hours ahead.
31.	**3.4.6**	OR	**Need Hourly Ramp Rates for Operating Reserve**	OPG requests clarification on whether Operating Reserve Ramp Rate is part of hourly offer submission or dispatch data submission. In the Operating Reserve Ramp Rate section, the design states (Page 48): *"A single operating reserve ramp rate is required for every dispatch hour an offer to provide operating reserve is submitted by the registered market participant."* It is recommended that the Operating Reserve Ramp Rate be an hourly submission that can vary for different hours of the day. Hourly submissions would allow Market Participants to submit OR Ramp Rates that reflect the changes to ramp rate that occur when coming online as a cold, warm, or hot unit. For example: Unit reaches MLP HE12, OR ramp rate 2 MW/min, HE13 5 MW/min, HE14 20 MW/min. The ramp rate of a resource is dependant on the thermal status and number of hours that it is synchronized at MLP. For example, a HOT unit will be able to achieve one set of ramp rates for the first hour from when it reaches its MLP and another set of ramp rates afterwards. It is recommended that a new parameter be introduced that will be able to identify what set of ramp rates to use and for which hours depending on the thermal state of the unit.
32.	**3.4.8**	Timelines	**Segregated Mode of Operation (SMO) timelines**	IESO proposes submission and cancellation timelines for SMO requests be revised in the future market. From the Grid and Market Operations Integration detailed design document it 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;"* OPG proposes that SMO transactions should not be limited in real time regardless of an outage to a critical transmission element. We would like some rationale as to why an outage to a critical transmission element should prevent a market participant from using SMO in real time. In addition OPG requests SMO in day ahead be revised to be made by 10:00 EPT, respecting the proposed DAM market timelines.

#	Section	Theme	Comment Name	Detailed Comment
				Please provide a definition of what constitutes a "critical transmission element", and provide a list of included elements. A market participant standardized report indicating the "critical transmission elements" on outage should be issued to participants notifying them of their limitations to request SMO.
33.	**3.4.8**	Additional Reporting	**Request for Confidential Outage Reports**	OPG requests that the IESO issues 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 created this additional reporting for pseudo units and recommends this be extended for all technology types as there have been 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.
34.	**3.5.1**	Additional Reporting	**Reporting of reliability commitments**	When a reliability commitment is given to an NQS in advance of first pre-dispatch run, will the IESO notify all market participants that such a commitment has been given, and for which specific hours of the day? OPG recommends this information be provided as part of a public report rather than a system advisory notice. This allows for archiving this report with similar data on a trade date. This is beneficial for after-the-fact analysis and may aid in ex-post discussions on Market Power Mitigation with the IESO.
35.	**3.5.1**	Forecasting	**Rationale required for setting Lake Erie Circulation Forecast to 0 MW**	Please provide information on why the IESO proposes to set the hourly forecast value to 0 MW when this is not the expected condition. OPG recommends the Lake Erie Circulation (LEC) Forecast be published in a standardized report prior to the Day Ahead Submission window opens (i.e. prior to 06:00 EPT) and also hourly during the Pre-dispatch timeframe, this report should also indicate any planned or forced outages to the Phase Angle Regulators (PARs), which would lead to the inability to regulate the flow for LEC.
36.	**3.5.2**	Pricing Inputs for negative MMCP	**Addressing the issue of negative pricing**	OPG had provided the following comments in our SSM HLD Stakeholder Feedback regarding negative pricing: *"OPG believes there is technically based merit for negatively priced offers and welcomes further discussion on this topic. Should changing the value of the negative MMCP be considered, it will be important to have a means for distinguishing dispatch order if there is insufficient price separation between supplier offers; in particular, energy limited renewable facilities."* The IESO's response to the feedback was the following: *"Thank you for your feedback. The issue of negative pricing will be addressed with stakeholder input in detailed design."* OPG did not see the issues around market participant's requirements to submit negative priced offers to provide sufficient price separation between offers for energy limited renewable facilities and its impact of potentially setting negative locational prices addressed in this detailed design document, and would appreciate some clarity

#	Section	Theme	Comment Name	Detailed Comment
				around how the IESO intends on addressing this topic. We would again welcome further stakeholdering and discussions on the subject of negative MMCP.
37.	**3.5.2**	Additional Reporting	**Reporting of changes to penalty prices**	For market transparency, the IESO should publish a report to inform market participants of changes to Penalty Prices with a frequency that allows Market Participants to adjust offers accordingly.
38.	**3.5.4**	Pricing	**Marginal Loss Factors and use of Dynamic Loss Factors**	As per previous comments on the high level design for the SSM, OPG does not support dynamic loss factors be updated more frequently than hourly due to experienced dispatch volatility issues when it was last implemented at market opening. In particular, the use of dynamic loss factors will make it challenging to maintain relative dispatch order for hydroelectric resources on a cascading river system. For example, hydroelectric stations often have two or more injection points and subsequently can have two or more loss factors. One may think these would be relatively similar due to geographic location, however, loss calculations are complex and may vary drastically depending on transmission connections and configurations. The losses become even more complicated when the injection points at the same station are on the 115 kV and 230 kV, causing electricity to travel different pathways to the reference bus. This difference in losses may cause the lower offered unit to be dispatched down and the higher offered unit to be dispatched up causing uncertainty in unit schedules that cannot be mitigated by offer strategy without an understanding of the estimated loss factors in real-time. If the IESO continues to pursue the use of dynamic loss factors in calculation engines, the IESO should perform analysis during sandbox testing and after GO-Live to determine whether the use of dynamic loss factors increases the number of dispatches to resources and has a roll-back plan if the number of dispatches increases or the quality of dispatches degrades. The real-time calculation engine will need to allow for compliance aggregation without potential for the engine to continually re-dispatch resources. See-saw dispatches cause wear and tear on resources with no apparent reason. An example of a see-saw dispatch (or degradation of dispatch quality) is as follows: • Actual Output 1: Resource A- 0 MW, Resource B -10 MW • Dispatch 1: Resource A - 10 MW, Resource B - 0 MW • Actual Output 2: Resource A -10 MW, Resource B - 0 MW • Dispatch 2: Resource A - 0 MW, Resource B - 10 MW • Back to Actual Output 1 and repeat.
39.	**3.5.4**		**Load Distribution Factors (LDF) - Selection Process for "Similar" Day**	Please provide clarification on the following statement in paragraph 2 of the Load Distribution Factors(s) sub-section: *"In the future energy market, the DAM and PD calculation engines will also use LDFs that are based on load patterns from the same day in previous weeks, for all hours except the first two hours of the PD calculation engine's look-ahead period."*

#	Section	Theme	Comment Name	Detailed Comment
				Following a stat holiday (e.g. the Friday after good Friday), or following a week/day with extreme weather or other circumstances, OPG recommends the IESO make exceptions to this rule to find a more suitable "similar" day.
40.	3.5.6	Forecasting	**Zonal Demand Forecasts**	Summing the demand forecast for the four zones to produce the province-wide demand forecast will magnify error and increase likelihood for more price volatility across zones, given that the four zonal forecasts will have already been rounded up to ensure self-sufficiency. Given Ontario's large geographic area, forecasting on a global level can offset errors inherent to zonal forecasting caused by rapidly changing weather patterns across smaller planning areas. OPG suggests the IESO offset this rounding impact when aggregating the four zonal forecasts into a single province wide forecast. Or develop the forecasts using a bottom-up approach (i.e. zonal forecasts that capture the unique load types by zone that are then aggregated up) rather than the top down approach that assigns shares. OPG suggests the IESO publish zonal forecasts that are distributed by nine zones, which are consistent with the nine virtual zones. This will allow Market Participants in each of these nine zones to plan their resources better based on expected zonal demand and zonal constraints.