Stakeholder Feedback Form

Date Submitted: 2020/11/04	Feedback Provided By:	
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Feedback Due: October 30, 2020	Phone:	[redacted]
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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 **October 30, 2020** to engagement@ieso.ca.

Please let us know if you have any questions.

IESO Engagement

General feedback on the Detailed Design Document (please expand any section as required)
OPG's detailed review comments for the **IESO Market Real Time (RT) Calculation Engine draft detailed level design** are provided in the tables below. OPG has submitted extensive comments on other key sections of the Detailed Design. OPG looks forward to working with the IESO to address/mitigate the issues we have identified so the final design can maximize market efficiency and minimize costs to customers. The following list provides a brief summary of the main themes in our comments and additional details on each is provided in the detailed comment table: a. The RT calculation engine equations are very detailed and complex. For market participants to gain a better understanding of their application the IESO should provide examples demonstrating their use including simple examples/scenarios illustrating solving of the objective function for scheduling and pricing, including the resulting outputs. Other equations for which OPG would like examples are listed in the detailed comments below. The IESO should also consider hosting webinars/workshops highlighting various calculation examples to provide better clarity to Market Participants. **Without these examples, OPG found it difficult to review the equations, apply them to scenarios or situations and provide adequate comments on the detailed design.** b. OPG made several detailed recommendations to improve the design of the new hydroelectric parameters in its review submission for the Offers, Bids and Data Inputs design section. The IESO has not yet provided any feedback on these recommendations in its responses posted on October 19, 2020 stating that feedback for the remaining comments would be provided in November. OPG may have additional comments on the calculation engine detailed designs once IESO has provided feedback on these previous recommendations. c. OPG recommends that the RT mandatory window timeframe be reduced 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 for example, the mandatory window is only 75 minutes. d. Constraints are not included in the RT calculation engine design for the following hydroelectric parameters: minimum hourly output, maximum number of starts per day and linked resources, time lag and MWh ratio. As stated in previous review comment submissions, OPG recommends the RT engine accept minimum constraints from the pre-dispatch calculation engine for these parameters to avoid hydroelectric resources from entering SEAL conditions in RT. e. There are many areas where additional reporting is needed to increase market transparency and for settlement reconciliation purposes. One example is the need to confidentially publish the economic operating point (EOP) for energy and the three types of operating reserve (OR). EOP impacts market participants Day Ahead (DA) Schedules, Pre-dispatch (PD) Schedules, RT Dispatches, assessment for make-whole payment mitigation, make-whole payments, etc… as such, this information is critical to market participants in all time frames.

#	Section	Comment Name	Detailed Comment
1.	General	OPG Proposed Changes to Hydroelectric Parameter Design	OPG made several detailed recommendations to improve the design of the new hydroelectric parameters in its review submission for the Offers, Bids and Data Inputs design section. This included recommendations for alternative wording to: • Minimum hourly output (MHO) • Forbidden regions • Daily Energy Limits (DELs) • Maximum Number of Starts Per Day • Linked Resources, Time Lag and MWh Ratio The IESO has not yet provided any feedback on these recommendations in its responses posted on October 19, 2020 stating that feedback for the remaining comments would be provided in November. OPG may have additional comments on the calculation engine detailed designs once IESO has provided feedback on these previous recommendations.
2.	General	No Discussion of ORAs in the Document	The design document does not provide any information on how Operating Reserve Activations (ORAs) will be treated. Some details that the IESO should provide include: 1. How does the calculation engine determine whether an ORA is needed? 2. How does the calculation engine determine which resources to activate and to what MW output? 3. Describe the interaction (if any) between ORAs and the pricing algorithm.
3.	General	Opening Mandatory Window for Demand Changes	When IESO makes significant (e.g. ±100 MW) changes to zonal demand and variable generation forecasts inside the mandatory window, it can have a significant impact on market results, without giving an opportunity for market participants to respond to these signals. OPG suggests that when IESO adjusts a forecast inside the mandatory window, they open the mandatory window for market participants to adjust offers/bids accordingly, to drive better market efficiency.
4.	Grid & Market Operations Integration, Section 3.3	Propose Shortening of RT mandatory window timeframe	OPG included a comment proposing that the duration of the RT Mandatory window be reduced from 110 minutes to 90 minutes in its review submission for the Grid and Market Operations, Integration Design. The IESO did not provide any feedback to this proposal in its review comment responses posted on its website on October 19, 2020. OPG has reproduced its previous comment below and encourages the IESO to adopt this proposal: *"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."*
5.	2.1.3	Dispatches that are not consistent with the DSO	In section 2.1.3 the design states: *"In certain circumstances, the actual dispatch instructions are different from the outputs of the DSO runs. These circumstances can arise when the IESO needs to intervene with the outcome of the dispatch algorithm by modifying or overriding the dispatch instructions for reasons related to system reliability. In such cases, prices and dispatch might not be aligned and may result in CMSC payments."*

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			The IESO should explicitly state whether they expect the circumstances above to exist after market renewal and provide examples of how market participants will be aware of these situations, market power mitigation is enforced, and how market settlement is impacted.
6.	2.2.1	Example Aggregation of Zonal Load Forecasts	In section 2.2.1 the design states: *"Five-minute demand forecasts will continue to be used as an input for the expected load in the RT calculation engine. However, the IESO will now produce the existing province-wide demand forecast as the sum of four separate demand forecast areas."* The IESO should provide an example of how the existing province-wide demand forecast is produced as the sum of four separate demand forecast areas.
7.	2.2.2	Example Required for Constraint Violation Penalty Curves	In section 2.2.2 the design states: *"Real-Time Pricing: Uses the same dispatch data and the set of IESO inputs from Real-Time Scheduling with one exception. Real-Time Pricing uses the constraint violation penalty curves that are relevant for pricing, instead of the constraint violation penalty curves for reliability. Real-Time Pricing also uses the principle for price-setting eligibility to determine settlement-ready LMPs again accounting for resource and system constraints."* The IESO should provide a detailed example that illustrates the difference between constraint violation penalty curves for pricing and reliability and the impact on settlement ready LMPs and shadow prices.
8.	2.2.2	Example for Calculation of Hourly Marginal Loss Factors and Need for Report on DA/RT Differences	In section 2.2.2 the design states: *"Marginal loss factors for each dispatch hour will be calculated in the hour preceding the dispatch hour. These marginal loss factors will then be held fixed for each interval in that dispatch hour. The same set of fixed marginal loss factors will be used for calculating schedules and prices."* The IESO should provide details on how marginal loss factors will be calculated in the hour preceding the dispatch hour. It is unclear whether they will be calculated and fixed as per pre-dispatch or whether there is separate process to calculate marginal losses. For market transparency and settlement reconciliation purposes, the results of the marginal loss factors should be published. The IESO should also report on the differences between DA marginal losses and RT marginal losses to avoid marginal loss calculation differences from negatively impacting market participants who have financially binding DA schedules.

#	Section	Comment Name	Detailed Comment
9.	2.2.3 / 3.8	Proposed -$100/MWh Settlement Floor Price Needs Further Stakeholdering	In section 2.2.3 the design states: *"Real-time prices will continue to be no greater than $2,000/MWh for Summary of the Current and Future State energy and $2,000/MW for operating reserve. Energy and operating reserve prices will be no less than -$100/MWh and $0/MW, respectively."* The proposed settlement floor price of -$100/MWh for energy is inconsistent with -$20 settlement floor value that the IESO had proposed at the Negative Pricing stakeholdering session. If the IESO is imposing a settlement floor price of -$100/MWh, it should be appropriately stakeholdered with market participants. Please provide the rationale for this new amount and the reason for the change from -$20. An appropriate settlement floor is necessary as highlighted by the IESO in the pre-reading material for the technical discussion on Negative Pricing, which states: *"Unlike the other options considered, the settlement floor permits hydroelectric facilities to continue to offer in a manner that allows them to manage the dispatch of their resources and thus to manage applicable water restrictions. The settlement floor will result in efficient price signals and appropriate settlement results. This would not necessarily be the case without such a floor.* *Without introducing a settlement floor market participants could be exposed to an inefficient and inappropriate settlement that could result in a significant financial impact. For example, assume a resource with positive marginal costs required 10 minutes to ramp from its current schedule of 100 MW down to 50 MW. If a transmission limit suddenly bound, the generator's LMP could (in the extreme) be -$2,000/MWh while it ramps down. Assuming a linear ramp down, the generator would have injected an average of 87.5 MW in the first interval and 62.5 MW in the second. As a result, the market participant would pay 150 MW x -$2,000/MWh / 12Int = -$25,000 during its two-interval ramp down."* In the IESO's scenario above using a settlement floor of -$20, the market participant would pay 150 MW *-$20/MWh/12 int = -$250 during its two-interval ramp down. Whereas the new settlement floor of -$100, results in a payment of -$1,250 for its two-interval ramp down. The significance in the proposed change from -$20 to -$100 becomes even larger when reviewed in the context that the Negative Pricing pre-reading also states: *"However, in certain regions in Ontario, there are instances when locational prices[1] can be significantly less than $0/MWh. This has been most frequently observed in the Northwest of the province with negative prices occurring in roughly 10% of observed intervals between 2014 and 2016.[2]"*

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			The IESO should seek to quantify the benefits of the proposed change to the settlement floor and determine whether this change will require an additional mechanism to correct inefficient and inappropriate settlements. For example: Will this result in an additional make whole payment? In summary OPG would like to discuss the quantum of the Settlement Floor to ensure there are limited inefficient market outcomes and inappropriate settlement amounts.
10.	2.2.3	OPG's Ongoing Request for Additional Reporting in New Design	I section 2.2.3 the design states: *"Finally, the Publishing and Reporting Market Information process will produce a number of public, market participant confidential and internal IESO reports on the dispatch day resulting from the RT calculation engine. Refer to the Publishing and Reporting Market Information detailed design document for details."* OPG suggests that V1.0 of the Publishing and Reporting Detailed Design remains under review with many of IESO responses to stakeholder feedback including OPG's requests for additional details on reports and for the introduction of additional reports as: *"This request will be considered during the Implementation Phase."* A key concern for market participants is the enhanced need for market transparency: timely market results will enable market participants to adapt energy limited resource (ELR) optimization strategies to drive market and operational efficiencies as well as providing certainty to market participants of future dispatch schedules.
11.	Figure 2-2	Omission of Hydroelectric Parameters from Future RT Engine Figure	Figure 2-2: Future RT Calculation Engine Process does not include RT constraints as proposed by OPG in Offers, Bids and Data Inputs detailed design comments.
12.	3.3	Example of Multi Interval Optimization (MIO) and Price-Setting	In section 3.3 the design states: *"The RT calculation engine will perform multi-interval optimization to plan real-time dispatch for the next 11 five-minute intervals. In each set of 11 five-minute intervals, the first interval is the dispatch interval, and the remaining intervals are advisory intervals.* *The optimization will be performed over multiple intervals so resources can be scheduled in advance of actual requirements. For example, ramp capability can be used to solve for anticipated changes in operating conditions and therefore help prevent unresolvable security violations from manifesting in real time."* Please provide an example of how MIO will be performed and how it sets RT price.

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13.	3.3	Example of Economic Evaluation for NQS Unit Shutdowns	In section 3.3 the design states: *"The RT calculation engine will respect the operational commitments determined by the DAM and PD calculation engines for NQS resources. When an operational commitment expires, the RT calculation engine will evaluate the resource according to the economics of its energy offers to determine if the resource is to be shut down."* Please provide an example of how the RT calculation engine evaluates the economics of a resource's offers to determine if the resource is to be shut down.
14.	3.3	Inclusion of Hydroelectric Parameters in RT Calculation Functions	On page 13, the design lists all items that are fixed for the hour as: *"The RT calculation engine will respect the operational commitments determined by the DAM and PD calculation engines for NQS resources. When an operational commitment expires, the RT calculation engine will evaluate the resource according to the economics of its energy offers to determine if the resource is to be shut down. Intertie schedules will be fixed for each interval of the multi-interval optimization according to the schedules calculated by the pre-dispatch scheduling processes and established as per the intertie check-out procedure. These schedules will be fixed within an hour and ramping between these schedules will be performed in the interval preceding and interval succeeding the top of the hour. Dispatch schedules for hourly demand response resources are also determined during the pre-dispatch scheduling processes and are fixed within an hour."* This paragraph should also contain the minimum schedules for hydroelectric, such as, constraints required for linked resources on cascade river systems and resources with minimum hourly output (MHO) amounts as scheduled in PD-1.
15.	3.3	Examples/Scenarios for Price Setting Eligibility – RT LMPs vs. DA & PD	In section 3.3 the design states: *"A pricing algorithm will calculate location marginal prices (LMPs). It will primarily use the same set of market participant inputs, IESO inputs and resource and system constraints as the scheduling algorithm. It will determine settlement-ready LMPs by performing a security-constrained economic dispatch allowing an offer or bid lamination to set price in accordance with the principle for price-setting eligibility."* Please provide details of any differences between price setting eligibility that occur due to the differences between Day Ahead (DA), Pre-dispatch (PD), and Real Time (RT) calculation engines. Examples or scenarios may be useful to illustrate the differences.
16.	3.3	Details for Calculation of Fixed Marginal Loss Factors	In section 3.3 the design states: *"3. Loss calculation: The base case solution will calculate the loss adjustment used in the energy balance constraint of the optimization function. Unlike in the DAM and PD calculation engines, the marginal loss factors will not be updated by the security assessment function. Rather, fixed marginal loss factors will be used for all intervals within the same dispatch hour."*

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			Please provide details on how the fixed marginal loss factors are calculated for a dispatch hour.
17.	3.4.1.2	Definitions of Internal Resource, Electrical Location and Bus	In section 3.4.1.2 the design states: *"If more than one internal resource is connected to the IESO-controlled grid at the same electrical location, they will be considered to be at separate buses for the purposes of the optimization function."* Please provide an example to clarify how the IESO defines an internal resource, electrical location, and bus for the purpose of the optimization function. If two non-variable generating resources connected at the same electrical location have equal energy offers, how is tie-breaking determined?
18.	3.4.1.3	Clarification on Ramp-up/Down Rates in RT Calculation Engine	On page 18, the design states: *"The RT calculation engine will respect the energy ramping constraints determined by the submitted MW quantity (up to five), ramp up rate and ramp down rate value sets described above. The optimization function formulations provided in this document assume one ramp up rate ($URRDL_b$ for $b \in BDL$) and one ramp down rate ($DRRDL_b$ for $b \in BDL$) apply across the entire operating range of a dispatchable load."* Please confirm the one ramp rate up and down is for simplification of the document and not representative of the calculation engine. If not, the IESO should provide justification for why multiple ramp rates are not accepted by the RT calculation engine for dispatchable loads.
19.	3.4.1.3	Clarification Regarding Operating Reserve for Exports	In section 3.4.1.3 p.19 the design states: *"$F10NXLSch_i$, shall designate the fixed quantity of non-synchronized ten-minute operating reserve scheduled from the exporter..."* Does the above imply that the IESO will develop processes to allow exporters to offer operating reserve on interties? If so, could the IESO describe the processes that it intends to develop to coordinate with other jurisdictions?
20.	3.4.1.3	Acceptable types of Fixed Export Schedules	The section *Export Schedules* on p.19 states that fixed export schedules: *"...may include emergency sales or inadvertent payback transactions."* The IESO should clarify its definition of fixed exports. There are other types of exports that could be considered "fixed" (e.g., Installed Capacity obligations to external jurisdictions), and OPG suggests changing the phrasing to "may include but are not limited to..."

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21.	3.4.1.3	Settlement for No-bid Dispatchable Load	As per page 19 of the design: *"In circumstances when a dispatchable load without an active bid is observed through telemetry to be withdrawing energy from the IESO-controlled grid, the optimization function will assign a fixed schedule to this resource as determined by telemetry. This treatment will support the ability of a dispatchable load to designate its entire consumption as non-dispatchable by not submitting an active bid."* Please identify any difference in settlement for dispatchable loads that do not have an active bid.
22.	3.4.1.4	Clarification on no-offer generation	In section 3.4.1.4 the design states: *"Supply inputs can belong to one of the following categories: …* • *Schedules for generation without an active offer currently injecting into the IESO-controlled grid, known as no-offer generation; …"* Please provide clarification on what is considered no-offer generation and how this type of generation is assessed for compliance and settled.
23.	3.4.1.4	Clarification on Use of Metered Values	In section 3.4.1.4 the design states: *"The observed output of a self-scheduling generation facility as measured by telemetry will be used to determine a fixed schedule across the MIO look-ahead period in respect of the offer quantity provided by the facility, where:* $FNDG_{i,b}$ shall designate the fixed schedule for the non-dispatchable generation resource at bus $b \in BNDG$ for interval $i \in I$." Please confirm that the fixed schedule above is independent of the offered schedule submitted and is solely dependent on metered values.
24.	3.4.1.4	Transfer of Inputs/Parameters from PD to RT through Rolling 60-minute look-ahead period	In section 3.4.1.4 the design states: *"The RT calculation engine evaluates the additional dispatch data submitted differently than the DAM and PD calculation engines because the RT calculation engine considers a rolling 60-minute look-ahead period."* Please provide examples of how intertie schedules, Minimum Hourly Output (MHO), Hourly Must Run (HMR), hydroelectric linked resources, min DEL constraints, etc. are transferred from the PD Calculation Engine to the RT Calculation Engine. OPG notes how this works will impact the MIO look-ahead period which will impact resource dispatches.

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25.	3.4.1.4	Examples of Variable Generation MIO	In section 3.4.1.4 the design states: *"For each registered facility supplying variable generation, the IESO will continue to provide production forecasts for all intervals of the MIO look-ahead period. For the variable generation resource at bus $b \in BVG$:"* Please provide an example of how the variable production forecasts used in MIO are integrated with variable generation offers, variable curtailments, and dispatches to other generation types.
26.	3.4.1.4	Clarification Required on Forbidden Zones	In Table 3-5 the design states: *"…shall designate the lower and upper limits of the resource's forbidden regions in interval $i \in I$ indicating that the resource cannot stably operate between $ForL_{i,b,w}$ and $ForU_{i,b,w}$ for all $w \in \{1,..,NFor_{i,b}\}$ and must be ramped through this region at its maximum offered ramp capability."* Please clarify whether a resource can be scheduled or dispatched within the lower and upper bound of the forbidden range. If this is a possibility, an example should be provided to illustrate when this may happen.
27.	3.4.1.4	Scheduling of No Offer Generation	On page 24 the design states: *"In circumstances when a generation resource without an active offer is observed through telemetry to be injecting into the IESO-controlled grid, the RT calculation engine will schedule this resource as required by the IESO to enable system reliability."* Please provide an example that explains the scheduling performed by the RT calculation and in what situations this would occur.
28.	3.4.1.4	Example of Adjustment for Emergency Purchases	On page 24 the design states: *"Because the PD calculation engine import schedules from the scheduling and pricing algorithms are carried forward, the adjustments for emergency purchases that do not support a sale will persist in real time. Therefore, transactions corresponding to emergency purchases that do not support a sale will not be scheduled in the pricing algorithm of the RT calculation engine even though they are scheduled in the scheduling algorithm."* Please define what the IESO considers adjustments for emergency purchases that do not support a sale. The IESO should also provide an example of adjustments for emergency purchases that do not support a sale that persist in real time impact price since they are not scheduled in the pricing algorithm.
29.	3.4.1.4	Need RT Constraints for New Hydroelectric Parameters	The RT engine design identifies the hydroelectric parameters that will be respected in the RT calculation engine as: 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

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			of the dispatch day. OPG recommends the real time engine must also include the minimum constraints from the PD 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 RT. OPG included a similar comment in its review submission for the Grid and Market Operations Detailed design, as well as two additional comments with additional information and recommendations. These two supporting comments are reproduced below in the next two comments.
30.	Grid & Market Operations Integration, Section 3.7.2.2	Comment #43 from Grid & Market Operations Integration Review: 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.
31.	Grid & Market Operations Integration, Section 3.7.2.2	Comment #44 from Grid & Market Operations Integration Review: Linked resource, time lag and MW ratio parameter needs to transfer to RT	The IESO design states the following in Section 3.7.2.2 of Grid & Market Operations Integration: *“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

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			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.
32.	3.4.1.5	Need Visibility of Marginal Loss Factors Prior to Close of Mandatory Window	In section 3.4.1.5 the design states: *"Losses will be modelled in the RT calculation engine using marginal loss factors and a loss adjustment. The marginal loss factors for each interval in a given dispatch hour will be fixed at the same value. As described in Section 3.7.2.3, the marginal loss factors used will coincide for all intervals within the same dispatch hour…"* OPG acknowledges the IESO has made a prudent decision to fix the marginal loss factors for each interval in a given dispatch hour at the same value. However, market participants should have the ability to view these marginal loss factors before the close of the mandatory window. Without the ability to revise offers based on marginal loss factors dispatches may not align with market participants' intentions, which could lead to violation of SEAL restrictions.
33.	3.4.1.5	Additional Reporting - Operating Reserve Requirements	In section 3.4.1.5 the design states: *"In addition, the IESO will define several regions within Ontario that will have their own regional operating reserve minimum requirements and maximum restrictions. Each region shall consist of a set of buses at which operating reserve scheduled may be used to satisfy the minimum requirement for that region and is limited by the maximum restriction for that region…"* OPG recommends transparent reporting of regional operating reserve minimum and maximum restrictions as these IESO inputs impact OR scheduling, pricing, and potentially market power mitigation actions by the RT Calculation Engine.
34.	3.4.1.5	Additional Reporting - Dispatchable Generation Reliability Constraints	In section 3.4.1.5 the design states: *"Reliability constraints: The IESO will identify resources that must operate for reliability purposes. The IESO may, as required, place minimum or maximum constraints on these resources …"* The IESO should publish confidential reports as far in advance as possible for any resources with reliability constraints. OPG notes that resources with reliability constraints are subject to a stringent assessment of conduct and impact testing and if mitigated this result is required for reconciliation of settlements.
35.	3.4.1.5	Clarification Required - Dispatchable Generation resources - Regulation	In section 3.4.1.5 the design states: *"Regulation: The IESO will continue to enter into contracts with market participants for certain dispatchable generation resources to provide regulation. RT offers must be submitted for such generation resources. A resource providing AGC will be*

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			scheduled to at least the more restrictive of its minimum AGC limit and its minimum loading point plus the designated AGC range." 1. Please clarify how the minimum AGC limit will be applied to a station that has many resources providing AGC and a shared minimum AGC limit. 2. Please clarify the price setting eligibility of an AGC resource.Please provide an example which illustrates the settlement of an AGC resource with a 50 MW Day Ahead Schedule which was reduced to 40 MW in RT. DA $50, RT $40. 3. Please provide an example which illustrates the settlement of an AGC resource with a 50 MW Day Ahead Schedule which was increased to 60 MW in RT. DA $50, RT $40.
36.	3.4.1.5	Additional Reporting Needed for Operating Reserve Requirements	In section 3.4.1.5 the design states: *"In addition, the IESO will define several regions within Ontario that will have their own regional operating reserve minimum requirements and maximum restrictions. Each region shall consist of a set of buses at which operating reserve scheduled may be used to satisfy the minimum requirement for that region and is limited by the maximum restriction for that region"* The IESO should publish the regional OR minimum and maximum requirements, as well as the set of buses able to satisfy or are limited by the requirements.
37.	3.4.1.5	Examples Required - Constraint Violation Penalties	In section 3.4.1.5 the design states: *"To ensure the RT calculation engine can always find a feasible solution, it will be allowed to violate certain system constraints at a cost.[5] This will be achieved via constraint violation penalty curves, which establish the value placed on satisfying a constraint and indicate the relative priority of satisfying a certain constraint compared to other constraints. The constraint violation penalty curves used by the scheduling algorithm to produce constrained schedules may differ from the constraint violation penalty curves used by the pricing algorithm to calculate market prices in order to produce settlement-ready prices."* Please provide examples that demonstrate how the constraint violation penalty curves differ between the scheduling and pricing runs.
38.	3.6.1.4	Use of Real Time Telemetry - Resource Initial Conditions	In section 3.6.1.4 the design states: *"Resource initial schedules will be used as the initial loading point for a resource when determining its schedule for the dispatch interval. Accordingly, these initial schedules will be determined in respect of real-time telemetry and offered ramp rates to verify that the initial schedule is compliant with a resource's physical capabilities."*

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			Please clarify which real time telemetry the IESO will use to determine initial conditions (i.e., revenue metering, operational metering, or another source). Will the initial conditions be determined net of station service loads?
	3.4.1.5	Tie-Breaking modifiers for variable generation	The IESO should provide details on how the tie-breaking modifiers for each variable generator will be determined (i.e. the TMB_b value). Will the values be the same in the day ahead and real-time markets and how often will they change (e.g. monthly, daily, hourly)?
39.	3.6.1.2	Example of Using Tie-breaking to Determine Schedules	Please provide an example of how the calculation engine would determine schedules when there are two or more equivalent offers for energy or operating reserve. For example, how would the engine schedule dispatchable generators in the following scenario: Load = 45 MW Generator A: offered 50 MW Generator B: offered 14 MW Generator C: offered 26 MW Assume that the calculation engine deems each of these offers to be "equivalent", and therefore must use the tie-breaking methodology outlined in section 3.6.1.2. To extend the above example, how would the schedules for each generator change if one of the units (e.g., Generator A) had a forbidden zone where it would have "normally" been scheduled in the absence of the forbidden zone?
40.	3.6.1.4	Interaction of OR Activations (ORAs) with Forbidden Zones	The constraint equations to prevent hydroelectric resources from being scheduled within a forbidden region (p. 45) only appear to include terms for scheduled energy. **IESO should consider the need for an additional constraint that prevents scheduled energy plus scheduled OR from landing in a forbidden region**. If the combined DA schedules for energy and OR fall within a forbidden region, then subsequent OR activation may be infeasible. In the current market, the IESO sends ORAs within a forbidden region which may cause market participants to generate above the ORA to ensure the activation is deemed successful. The IESO should address this existing deficiency in market design.
41.	3.6.1.4	Application of Non-negative Schedule to Energy Storage	In section 3.6.1.4 the design states: *"No schedule can be negative, nor can any schedule exceed the quantity offered for the respective market (energy and operating reserve)."* Please provide additional information on how a non-negative schedule will be applied to energy storage resources, specifically, the load portion of the continuous offer curve which would likely require a negative schedule.
42.	3.6.1.4	Timing of Variable Generation Forecast	On page 40 the design states: *"The maximum output of a dispatchable variable generation resource will additionally be limited by its forecast."* Please clarify whether the forecast is hourly or on an interval basis.

#	Section	Comment Name	Detailed Comment
43.	3.6.1.4	Proposed Energy + OR Parameter Not Included in RT Engine Design	On page 43 the design states: *"The total operating reserve (10-minute synchronized, 10-minute non-synchronized and 30-minute) from a dispatchable generation resource cannot exceed its ramp capability over 30 minutes. It cannot exceed the remaining capacity (maximum offered generation minus the energy schedule). Lastly, it cannot exceed its unscheduled capacity …The amount of ten-minute operating reserve (both synchronized and non-synchronized) that a dispatchable generation resource is scheduled to provide cannot exceed the amount by which it can increase its output over 10 minutes, as limited by its operating reserve ramp rate."* Please clarify how the RT calculation engine determines the capacity available for operating reserve. How does the engine ensure that energy limited resources (e.g. hydroelectric) have sufficient energy remaining for ORAs. It appears that the Energy + OR parameter proposed by OPG in previous review comment submissions has not been included in the design.
44.	3.6.1.4	Examples of Operating Reserve Scheduling	On page 43, the design states: *"The amount of synchronized ten-minute operating reserve that a dispatchable generation resource is scheduled to provide is limited by its synchronized ten-minute operating reserve loading point…The amount of thirty-minute operating reserve that a dispatchable generation resource is scheduled to provide is limited by its 30-minute reserve loading point."* Please provide examples where: 1. The amount of 10S OR scheduled is limited by its 10S reserve loading point. 2. The amount of 30R OR scheduled is limited by its 30R reserve loading point.
45.	3.6.1.4	Hydroelectric Scheduling Through of Forbidden Region	On page 45, the design states: *"A hydroelectric resource will be scheduled in its forbidden region only if the resource is being ramped through the forbidden region at its maximum offered ramp capability."* Please provide an example where a hydroelectric resource is scheduled within its forbidden region.
46.	3.6.1.4	Example of NQS "stutter step"	On page 45, the design states: *"As in today's DSO, the RT calculation engine will account for the initial slow loading characteristics of NQS resources to avoid the "stutter step" that would otherwise occur when an NQS resource starts to increase output from either a steady load or at a loading rate less than the offered rate."* Please provide an example of how the RT calculation accounts for the "stutter step".
47.	3.6.1.7	Reporting of Real Time Scheduling Outputs	In section 3.6.1.7 the design states:

#	Section	Comment Name	Detailed Comment
			"The RT calculation engine will record all such values for informational purposes. Internal resource schedules are provided to market participants at a 0.1 MW granularity. The schedules calculated for the dispatch interval will be used to form the dispatch instructions that are provided to registered market participants for dispatchable load and dispatchable generation resources." For market transparency and settlement reconciliation, the IESO should publish in confidential reports the outputs of Real Time Scheduling.
48.	3.6.2	Confirm Ramp-rate Used in RT Pricing	In section 3.62 the design states: *"The initial resource schedules in Real-Time Pricing will use the initial schedules from Real-Time Scheduling. To facilitate calculating settlement-ready prices, the initial resource schedules of Real-Time Pricing also consider schedules from the pricing algorithm of the preceding RT calculation engine run."* Please confirm Real-Time pricing will use 1 x ramp rate not 3 x ramp rate.
49.	3.6.2.4	Price Setting Eligibility and Constraints for Hydroelectric Parameters	This section includes brief description of price setting eligibility rules for forbidden regions but there is no mention of other hydroelectric parameters including: Minimum Hourly Output, Hourly Must Run, Linked Resources, or Minimum Daily Energy Limit. Please clarify how these parameters affect price setting eligibility in RT.
50.	3.7.2.3	Clarification Needed on Fixed Marginal Loss	In section 3.7.2.3 the design states: *"The RT calculation engine will use a set of fixed marginal loss factors for each dispatch hour calculated in advance of the dispatch hour. The same set of fixed marginal loss factors will apply to all five-minute intervals of the dispatch hour. The scheduling and pricing algorithms will use the same set of fixed marginal loss factors. The set of fixed marginal loss factors will be determined based on the marginal loss factors calculated in the pre-dispatch hour by the scheduling algorithm of the RT calculation engine."* Please provide details on which pre-dispatch hour run (i.e. PD-3) will be used to set the fixed marginal loss factor for RT and how the IESO intends to publish these fixed marginal loss amounts. Marginal loss factors will impact dispatch of resources and should be transparent to market participants.
51.	3.7.3	Reporting of Loss Adjustment, Sensitivity Factors, and Fixed Marginal Losses	In section 3.7.3 the design states: *"The following outputs of the security assessment function will be provided to the optimization function:*

#	Section	Comment Name	Detailed Comment
			— *Loss adjustment quantity for every interval which is needed to correct for any discrepancy between total losses in the IESO-controlled grid obtained from the base case power flow and the linearized losses calculated using marginal loss factors;* — *The linearized constraints for all violated OSLs and pre-contingency thermal limits for each interval; and* — *The linearized constraints for all violated post-contingency thermal limits for each interval.* *The sensitivity factors and fixed marginal loss factors described in Section 3.7.2.3 will also be used in LMP calculations."* For market transparency, the IESO should publish loss adjustments, sensitivity factors, and fixed marginal losses. The design mentions sensitivity factors are described in Section 3.7.2.3, but this does not appear to be the case. Please provide more details on sensitivity factors.
52.	3.8	Examples Showing Impacts of Load Distribution Pattern on Price	In section 3.8 the design states: *"The load distribution pattern as provided to the security assessment function will be used to determine the weight assigned to each bus in contributing to the zonal price for a non-dispatchable load zone. The weighting factors will be obtained by renormalizing the load distribution factors so that the sum of weighting factors for an individual zone is one."* Please provide an example that would allow market participants to model the potential impact on zonal price (both for non-dispatchable loads and virtual transactions). For market transparency, the load distribution pattern should be publicly reported.
53.	3.8.1.1	Examples of Reference Price Modifications	The design states that an LMP can be modified when it is not initially within EngyPrcFlr and EngyPrcCeil. Please provide an example of how LMPs will be modified in such a situation. Also, please demonstrate with an example the effects on the loss and congestion components of other LMPs when the reference price initially falls outside the bounds of EngPrcFlr and EngyPrcCeil.
54.	3.8.1.2	Example of Import-Congestion During Pre-Dispatch	Please provide an example showing how intertie settlement prices (ISP), intertie congestion prices (ICP), and intertie border prices (IBP) are calculated when an intertie is import-congested in pre-dispatch. Please provide an example of this calculation both when the ISP is equal to the IBP and when the ISP is equal to the pre-dispatch intertie LMP.
	3.8.1.2	Example of Congestion and NISL Component Pro-rating	Please provide an example of how the intertie and Net Interchange Scheduling Limit (NISL) subcomponents will be prorated based on their PD magnitudes if ICP in real time differs from the pre-dispatch ICP. The NISL mechanism is flawed in today's market, which has resulted in the Market Surveillance Panel (MSP) making recommendation 2-1 in their May 2014-October 2014 Report. It stated: *"The Panel recommends that the IESO assess the methodology used to set the intertie zonal price for a congested intertie when the Net Interchange Scheduling Limit is binding or violated, in order to make the incentives provided by the intertie zonal price better fit the needs of the market"*

#	Section	Comment Name	Detailed Comment
			Does the IESO expect the proposed calculation engine mechanisms to address the concerns raised by the MSP?
55.	3.8.1.2	Example of Export-Congestion During Pre-Dispatch	Please provide an example of how the ISP, ICP, and IBP are calculated when an intertie is export congested in pre-dispatch.
56.	3.8.1.1	Example of Energy LMPs for Internal Nodes	In section 3.8.1.1 the design states: *"The reference price and loss component together reflect the cost of meeting load at bus b, incorporating the effect of marginal losses and reflect the quantity of energy that must be injected at the reference bus to meet additional load at bus b. The congestion component reflects the cost of transmission congestion between the reference bus and bus b and is calculated by adding the individual incremental congestion costs for the binding transmission constraints on the path between the reference bus and bus b. Each congestion cost is obtained by multiplying the shadow price for the binding transmission constraint by the corresponding sensitivity factor for bus b."* Please provide an example to illustrate the above design incorporating how the sensitivity factor for bus b is determined.
57.	3.8.2	Clarification on Co-optimization vs Joint Optimization	The design uses the terms co-optimization and joint optimization. Please provide the definitions for these terms and whether they are interchangeable or have differing meanings.
58.	3.8.2.1	Operating Reserve Regions	Can the IESO provide details on the geographic layout of the Operating Reserve regions. Will they be the same as the new load zones?
59.	3.8.2.1	OR Settlement Bounds	In section 3.8.2.1 the design states: *"An operating reserve LMP can fall outside the settlement bounds of … as a result of joint optimization or constraint violation pricing. When this occurs, the operating reserve LMP and its subcomponents (reference and congestion) will be modified so that the LMP is within the settlement bounds.* Please provide an example to illustrate how joint optimization and constraint violation pricing may require the use of the OR Price Floor of $0 or OR Price Ceiling of $2,000 to be modified within the settlement bo3.unds.
60.	3.8.3	Pricing for Islanded Nodes	The design states that the procedure for calculating LMPs for islanded nodes is as follows: *"1. Find connection paths over open switches that connect the NQS resource to the main island.* *2. Determine the priority rating for each connection path identified based on a weighted sum of the base voltage over all open switches used by the reconnection path and the MW ratings of the newly connected branches.* *3. Select the reconnection path with the highest priority rating, breaking ties arbitrarily.* *4. Use the LMP at a node in the node-level substitution list, provided such node is connected to the main island.* *5. If no such nodes are identified, use the average LMP of all nodes at the same voltage level within the same facility that are connected to the main island.*

#	Section	Comment Name	Detailed Comment
			6. If no such nodes are identified, use the average LMP of all nodes within the same facility that are connected to the main island. *7. If no such nodes are identified, use the average LMP of all nodes from another facility that is connected to the main island, as determined by the facility-level substitution list.* *8. If a price is yet to be determined, use the LMP for the reference bus."* Please provide an example of how the engine will perform this procedure. Please specify how ties will be broken "arbitrarily" as described in step 3. Lastly, if a region is not considered islanded in the Day Ahead timeframe, but becomes islanded in Real time, how are make-whole payments for resources in the islanded region affected? For example, if a resource with a Day Ahead commitment is unable to generate in real time due to islanding, will it be subject to balancing payments in real time?
61.	3.9	Adjustment of Offers in Mandatory Window Following Ex-Ante Mitigation	The design states: *"...the RT calculation engine will use reference levels for dispatch data parameters that failed the price impact test in the pre-dispatch scheduling process"* Reference levels may not reflect the offering intentions of market participants and could cause dispatches in real time that increase the likelihood of violating SEAL restrictions. To avoid this, market participants should have the ability to adjust offers in the mandatory window to maintain compliance with SEAL restrictions while respecting reference level thresholds. If the RT calculation engine strictly uses reference levels for resources that failed the conduct test, this could limit market participants ability to reorient their offers. Will the real time calculation engine have the ability to accept new offers in the mandatory window for resources that failed the impact test and whose offers were replaced with reference levels?
62.	3.9	Private Reporting of Economic Operating Point (EOP)	In section 3.9 the design states: *"The IESO may take control actions in real time to maintain system reliability, such as manually setting minimum or maximum constraints on a resource's dispatch schedule. This can result in a resource being dispatched up or dispatched down from their economic operating point, which may result in the resource receiving make-whole payments."* For market transparency and settlement reconciliation purposes the IESO should confidentially publish the economic operating point (EOP) for energy and the three types of OR. EOP impacts market participants DA Schedules, PD Schedules, RT Dispatches, assessment for make-whole payment mitigation, make-whole payments, etc… as such, this information is critical to market participants in all time frames.
63.	3.9.1	Reporting of Pre-Settlement Mitigation Process	In section 3.9.1 the design states:

#	Section	Comment Name	Detailed Comment
			"The following information from the RT calculation engine run will be required to generate data for the make-whole payment impact test: *. A list of resources that have reliability constraints applied as part of control actions, which were entered as an input to Pass 1;* *. For each resource with such a reliability constraint, a list of 5-minute intervals over which the reliability constraint was applied; and* *.A list of resources that submitted new offers during the real-time mandatory window, which were accepted by the IESO."* For market transparency and settlement reconciliation, the IESO should publish confidential reports with the information listed above.
64.	3.9.2	Enhanced Mitigated for Conduct Data Set	In section 3.9.2 the design states: *"The outputs from the Pre-Settlement Mitigation process will be the enhanced mitigated for conduct dispatch data set. This data set will include the additional data that is necessary for the make whole payment impact testing in the settlement process."* For market transparency and settlement reconciliation, the IESO should confidentially publish the enhanced mitigated conduct dispatch data set.