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Pre-Dispatch Calculation Engine Feedback Responses

Below are the IESO's responses to stakeholder feedback on the Pre-Dispatch (PD) Calculation Engine detailed design document.

ID	Stakeholder	Feedback	IESO Response
N/A	Multiple	Multiple stakeholders asked for examples, scenarios, and walkthroughs of the detailed design.	The IESO has been working with stakeholders collaboratively through the Detailed Design discussion, to further the understanding of stakeholders, and provide background, clarification, and rationale where needed. Further, the IESO has focused on providing background and examples to stakeholders, both in writing and in various stakeholder forums, that answer specific requests. The IESO and stakeholders recognize that the transition to a renewed market can bring forward many requests for scenarios or examples on the impacts on participants, and the IESO will aim to respond to these requests that provide the greater value to the broad stakeholder community, and provide the greatest efficacy. Stakeholders are also encouraged to engage resources to provide them strategic advice on to navigate the nuances of their participation in the renewed market.
802	Association of Major Power Consumers in Ontario (AMPCO)	As with the Day-Ahead Market (DAM) design, this document provides the math for the constraint penalty violation curves. As we asked in two last rounds of Detailed Design documents, we would like the IESO to walk stakeholders through examples of these curves, particularly the various Operating Reserve (OR) violation curves. This has an important impact on price and we would like to fully understand this prior to the finalization of the Detailed Design phase. It seems odd that subsequent documents have included no improvements on this matter, yet several diagrams are included in this document including one on the use of thermal states for Non-Quick-Start units.	The materials presented at the Constraint Violations stakeholder engagement meeting on November 25, 2019 describe the interrelationship of the operating reserve penalty curves and include supporting graphs and illustrations. The curve quantities and prices presented in the materials are used for illustrative purposes only. The actual values that will be used for the future market will be determined, and brought to stakeholders, during the development of market rules and market manuals.
803	AMPCO	The description of the use of demand forecasting is confusing and needs to be clarified. Section 3.7.1.3 seems to lump the forecasting of Non-Dispatchable Load (NDL) and Price Responsive Load (PRL) together, but section 3.11 clearly states that PRL forecasts and NDL forecasts are separate from one another. In addition, section 3.11 indicates that forecasted NDL load will be supplemented by forecasts for DL without a bid and PRL - without any indication in the document how these values will be calculated. The Real-Time (RT) Calculation Engine Detailed Design proposed that telemetry would be used for this, we can't understand how this could be viable in Pre Dispatch. This aspect of the design needs to be clarified.	The IESO will produce hourly average and hourly peak demand forecasts for each demand forecast area. These demand forecasts are representative of transmission losses and average or peak forecast consumption of all load facilities and hourly demand response resources in their respective demand forecast area. Like today, the future PD calculation engine optimization function will use an hourly province-wide non-dispatchable demand forecast quantity, which is inclusive of transmission losses. This forecast will be derived from the IESO's hourly average and peak demand forecasts, bid quantities from hourly demand response resources, and load distribution factors for non-dispatchable loads, price-responsive loads, and dispatchable loads without a bid. Sections 3.7.1.3 and 3.11 of the PD Calculation Engine detailed design document will be revised to enhance clarity on this topic.

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841	Electricity Distributors Association	We repeat that, in addition to identifying the required amendments to IESO Market Rules and Market Manuals, the IESO, the Ontario Energy Board (OEB), and the Ministry of Energy, Northern Development and Mines (MENDM) should proactively engage with LDCs and their customers to identify, scope, evaluate and decide on enabling legislative amendments, amendments to regulatory policy and amendments to regulatory instruments. For example, the IESO's published materials to date have not provided instruction as to which wholesale market price produced in the renewed market will be applied to non-RPP customers and it remains unclear how LDCs will be invoiced under MRP and, by extension, how their customers' bills will change. We continue to assume that the OEB will amend the formulas it uses to calculate Regulated Price Plan (RPP) prices to use the appropriate new wholesale market prices (e.g., the DAM Ontario Zonal Price). We also assume that the OEB will amend the formulas used in the Retail Settlement Code, e.g., to replace references to the Hourly Ontario Energy Price (HOEP) with the appropriate new wholesale market price clarifications. These changes to OEB codes will clarify how the electricity commodity charges for non-RPP customers, whose electricity commodity charges currently consist of the HOEP and Global Adjustment charges, are to be quantified in the reformed market. LDCs will be responsible for implementing revised, or possibly new, settlement and billing processes and will be the main point of contact for electricity customers with respect to changes on electricity bills.	Please see the IESO's response to this comment under the Day-Ahead Market Calculation Engine feedback (ID #644) that was posted on December 2 2020.
843	Electricity Distributors Association	We suggest that the IESO ensure consistency of terminology in this section relative to other Detailed Design documents.	Thank you for the feedback. The IESO will consider the use of consistent terminology when producing V2.0 of the detailed design documents.
844	Electricity Distributors Association	We characterize the Detailed Design as incomplete as it does not reference changes proposed by the interim design of the IESO's Storage Design Project. For example, the IESO does not include references to 'electricity storage participants' per MR -00445-R00-R05 ('Implementation of the Interim Storage Design'), which is currently being reviewed by the IESO's Technical Panel in preparation for consideration by the IESO's Board of Directors, the final step in the Market Rule amendment process.	Please see the IESO's response to this comment under the Day-Ahead Market (DAM) Calculation Engine feedback (ID #649) that was posted on December 2 2020.

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846	Electricity Distributors Association	With the publication of this last Detailed Design document, we note that the IESO now plans to respond to stakeholder feedback and produce v2.0 Detailed Design documents by end of January 2021, concluding the Detailed Design Phase of the MRP. We seek additional information from the IESO for the next phase of consultation on MRP. We recommend that the IESO outline plans for engaging with stakeholders through the implementation phase, such as final review of Detailed Designs, illustrating how stakeholder feedback was incorporated into the Detailed Designs, and tracking matters arising throughout the Detailed Design phase that will be consulted on throughout the implementation phase.	The remaining responses to stakeholder feedback on the detailed design and final versions of the detailed design documents will be published by the end of January 2021. A tracker document will be published with the final detailed design documents that lists the material changes made between V1 and V2. The tracker will specify the changes for each document, including the section, old value, new value, and reason for the change (e.g., stakeholder feedback, clarification). More information on engagement during the Implementation Phase can be found in the Stakeholder Engagement Plan – Energy Implementation document, posted on the Implementation Engagement web pages. There are active engagements for Reference Levels and Reference Quantities and Market Rules and Market Manuals, with dedicated web pages to keep stakeholders up to date. The Implementation engagement web pages will be updated throughout the Implementation phase with more information on existing and additional streams of engagement.
805	Ontario Power Generation (OPG)	The IESO should add a unique label/ID for every equation in the detailed design including those presented in the calculation engine sections and Market Settlements. This will make it easier to refer to specific equations during the implementation phase.	Thank you for the feedback. The IESO will take this feedback under consideration.
806	OPG	OPG included a comment proposing that the duration of the 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. [...]	Please see the IESO's response to this comment under the Grid and Market Operations Integration feedback ID #336, posted on December 2 2020.
807	OPG	When IESO makes significant (e.g. ±100 MW) changes to zonal demand and variable generation forecasts inside the mandatory window, it may 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.	Please see the IESO's response to this comment under the Real-Time Calculation Engine feedback ID #735, posted December 28 2020.
808	OPG	For market transparency, the IESO should confidentially publish the economic operating point (EOP) for energy and the three types of OR. EOP impacts market participant's 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. [...]	Please see the IESO's response to this comment under the Real-Time Calculation Engine feedback ID #796, posted December 28 2020.

ID	Stakeholder	Feedback	IESO Response
809	OPG	OPG has concerns with the timing of the first run of pre-dispatch. The initial planned run is scheduled for 20:00 and maintaining this time would not provide sufficient time for market participants to react to market signals prior to 00:00. In the current market, market clearing price (MCP) volatility is observed in HE1 and HE2 which may be worsened due to the later run of PD at 20:00. It is not likely that the introduction of a DA market which relies on both Primary Demand and Variable Generation forecasts will reduce the need for market participants to assess market signals and make decisions on how to offer generation in HE1 and HE2. Advancing to initial run to 18:00 instead of 20:00 would help to ameliorate this issue. Market participants will use PD market signals (i.e. pre-dispatch reports) to make decisions about how to operationalize DA schedules and react to changing market conditions such as changes to primary demand, wind generation forecasts, transmission outages, etc. If pre-dispatch engine information is not published until 20:00, the ability to react to market signals and re-offer resources to the market for HE1 and HE2 is very limited which may cause inefficient market incomes due to the lack of optimization between Day 1 and Day 2 resourcing schedules. In absence of this optimization, increased price volatility and inefficient unit commitments may limit the benefit of market renewal.	Please see the IESO's response to this comment under Grid and Market Operations Integration feedback ID #346, posted on October 19, 2020.
811	OPG	[...] 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.	Please see the IESO's response to this suggestion under the Real-Time Calculation Engine feedback (ID #746), posted on December 28 2020.

ID	Stakeholder	Feedback	IESO Response
812	OPG	[...] The linked resources, time lag and MWh ratio parameters are parameters used to manage the intertemporal dependencies of cascade hydroelectric facilities. If linked resources are not considered in real-time, there is an increased risk of having an "unbalanced" river system and market participants will be required to request IESO to constrain units on or force generation out to manage real time operating constraints that will cause market inefficiencies. OPG proposes logic that will transfer pre-dispatch schedules to real-time calculation engine in the form of minimum constraints to maintain balance on a cascading river system. When considering which pre-dispatch schedule was appropriate, OPG considered that the greatest flexibility would be able to be provided to the market by making the latest decision possible while weighing the need to break a link in PD-1 due to local inflow changes, outages, or other SEAL events. It is proposed that the IESO implement logic, transferring a minimum constraint equivalent to the PD-2 schedule to the real-time calculation engine for the upstream station of the cascade, with corresponding minimum constraints implemented based on the PD-2 schedule of the upstream station to the linked downstream stations. The downstream equivalents should receive minimum constraint schedules in real-time unless the links are broken/removed by the participant. Refer to OPG Comment #16 from Offers, Bids and Data Input Detailed Design.	Please see the IESO's response to this comment under the Real-Time Calculation Engine feedback (ID #763), posted on December 28, 2020.
813	OPG	The design states on Page 11: "The PD calculation engine will use a demand forecast of the forecast hourly peak demand for any hour where there is a significant difference between forecast peak demand and forecast average demand quantity." An example would better help with understanding the concept. What constitutes a "significant difference"?	As today, significant difference will continue to mean a difference of 300 MW or more between the forecast hourly peak and forecast hourly average demand.

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814	OPG	Page 11 of the design states: "The dispatch look-ahead DAM scheduled quantities for import and export transactions will limit import and export schedules beyond the first two forecast hours of the pre-period. Capacity imports/exports and imports to meet reliability needs are not limited by their DAM scheduled quantities in all forecast hours of the look-ahead period." Please clarify how the DAM scheduled quantities will "limit" import and export schedules beyond the first two forecast hours. Does the above paragraph mean that for hours beyond the first two forecast hours, the PD engine will not consider import/export schedules that are higher than the DAM schedule? If so, inefficient unit commitments may occur outside the first two forecast hours. [...]	The interpretation in the feedback is correct - beyond the first two forecast hours, the PD engine will not consider import offer and export bid laminations that are higher than a transaction's day-ahead market schedule. Exceptions will be made for capacity imports/exports and import transactions to meet reliability needs.
815	OPG	[...] Please clarify whether the "DAM scheduled quantities" referred to in this section [page 11] are the global DAM schedule on the intertie, a participant's total DAM schedule on the intertie, or the DAM schedule for a specific transaction? If a market participant submits economic bids via an additional transaction in PD, would the PD calculation engine consider those bids?	DAM scheduled quantities refers to the DAM schedule on a per-transaction basis. Under normal circumstances (i.e., no reliability events), the PD calculation engine would not consider bids of an additional transaction beyond the first two forecast hours of the look-ahead period because this additional transaction was not previously awarded a DAM schedule.
816	OPG	The top of Page 31 of the design includes the following statement: "Certain daily dispatch data parameters will be fixed to one value across the look-ahead period when the PD look-ahead period spans multiple dispatch days" Please specify which parameters will be fixed in this manner and provide an example across multiple dispatch days.	As described in Section 3.5.5 of the PD Calculation Engine detailed design chapter, the daily dispatch data submitted for the second day will be used when the pre-dispatch look-ahead period spans two dispatch days, for the following parameters: • Linked resources parameters • Minimum loading point (MLP) • Minimum generation block run-time • Minimum generation block down time • Lead time • Ramp up energy to MLP and Ramp up hours to MLP • Ramp up energy to MLP for combustion turbine and steam turbine portion
817	OPG	[...] Please clarify how the PD results are transferred and impact the RT calculation engine? If PD forecast is too low, will the resources output be limited/constrained to the max value in PD?	Like today, the PD results for variable generation resources and the hourly production forecast utilized in PD will not be transferred to the Real-Time (RT) calculation engine. The RT calculation engine will continue to utilize a separate, 5-minute production forecast.
818	OPG	[...] As per OPG's review comments on Offers, Bids and Data Inputs design section, MHO and MinDEL are also required to reflect operational constraints of hydroelectric stations similar to how Minimum Load Point (MLP) and Minimum Generation Block Run Time (MGBRT) are used by Non-Quick Start Units. The IESO did not include responses to OPG's previous comments on this topic in its feedback on Offers, Bids and Data Inputs provided on October 19, 2020.	Please see the response to the Offers, Bids, and Data Inputs (OBDI) feedback that was posted on December 2, 2020 under ID #218.

ID	Stakeholder	Feedback	IESO Response
819	OPG	On page 35 just below Table 3-10 the design states: "In circumstances where there is a conflict between the dispatch data parameter values submitted by a registered market participant for a hydroelectric facility, the engine would likely be unable to produce a solution. In such situations, the PD calculation engine will be permitted to violate conflicting constraints created by the dispatch data submitted, as required." If the PD engine needs to violate these constraints, the IESO should provide an order in which the constraints will be softened/violated. For example, if Hourly Must Run and Minimum Hourly Output conflict, the engine should violate the Minimum Hourly Output and not the Hourly Must Run. The order of constraint violations should be similar in day ahead, pre-dispatch and real-time to enable the calculation engines to consistently model physical operating constraints that become safety, equipment limitations, and applicable law (SEAL) restrictions in real-time. This approach should allow the IESO to resolve potential conflicts well in advance of real-time. […]	The calculation engines will use constraint violation penalty prices to determine the order in which to violate constraints, including those for applicable hydroelectric dispatch data parameters. The Offer Bids & Data Inputs Detailed Design will be updated to include additional hydroelectric violation prices in the Pricing Inputs section. The IESO understands that the Hourly Must-Run parameter should be treated as a fixed constraint. Accordingly, it will not have a corresponding violation price.
820	OPG	[...] Please clarify whether OR located in one zone can supply OR to a different zone. Please provide additional information about the OR areas and commit to publishing the OR requirements in all timeframes.	Operating Reserve (OR) located in one zone can supply OR to a different zone, subject to regional operating reserve maximum restrictions. The IESO currently issues Pre-Dispatch Area Reserve Constraints Report which will continue to be published under the Market Renewal Program (MRP). Please see Publishing and Reporting Market Information detail design document Table 3-14 report 3.
821	OPG	[…] The tie-breaking is defined as an hourly input data for each time-step t. In the DAM calculation engine design, tie-breaking is defined as a daily input data […] Can the IESO provide details on how the tie-breaking modifiers for each variable generator will be determined (i.e. the TMBb value)? Will the values be the same in the DAM and RTM and how often will they change (e.g. monthly, daily, hourly)? If the tie-breaking is an hourly input data, will the IESO continue publishing the tie-breaking data in the reports?	Please see the response to the DAM Calculation Engine feedback that was posted on December 2, 2020 under ID #665.

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822	OPG	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. [...] [...] 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?	Please see the response to the RT Calculation Engine feedback under ID #730.
823	OPG	Page 47 of the design states: "Similarly, the number of starts for hydroelectric resources must respect the number of starts already incurred as determined by the actual operation of the resource, plus any anticipated starts in time-step 1 of the look-ahead period" The above logic/methodology will need to be extensively tested during the IESO sandbox testing.	Thank you for your feedback. Information on testing will be shared with stakeholders later in the Implementation phase.
824	OPG	Page 47 of the design states: "The actual energy produced up to the current hour in the current dispatch day, plus the energy scheduled in time-step 1 of the look-ahead period, will limit the schedule of an energy-limited resource for the remainder of the current dispatch day. This quantity will also offset the amount of energy that must be scheduled to satisfy a hydroelectric resource's minimum daily energy limit." The above logic/methodology will need to be extensively tested during the IESO sandbox testing. The IESO should also consider that Min and Max DEL values may need to be resubmitting on an hourly basis to account for actual water used with a subsequent conversion to MWh of energy for both Min and Max DEL. The Max DEL submission may also be reduced if market conditions caused spill instead of generation.	As described in Section 3.3.7.6 of the Grid and Market Operations Integration detailed design document, changes to daily dispatch data parameters such as Min DEL and Max DEL can be revised on an hourly basis during the Real-Time Market Restricted Window for Daily Dispatch Data. Revisions to data must include a reason for the change that meets specific criteria that will be defined in the market rules. The criteria will be generally consistent with the existing criteria for allowing dispatch data revisions during the two-hour mandatory window - refer to Market Rules Chapter 7, Sections 3.3.6, 3.3.8, 3.3.11; and Market Manual 4.2, Appendix B. Revisions to Min daily energy limit (DEL) and Max DEL to account for actual/updated water conditions is expected to satisfy the above criteria.
825	OPG	Page 48 of the design states: "For linked hydroelectric resources, the past hourly energy production of upstream resources will be used to schedule downstream resources for time-steps in the look-ahead period within the time lag. These past hourly production schedules will be equal to the output measured by telemetry less any production scheduled as part of an operating reserve activation." This statement and the logic behind it will need to be re-assessed after the IESO responds to OPG recommendations around the treatment of cascade river systems as part of the feedback provided on Offers, Bids, & Data Inputs and Grid & Market Operations Integration detailed design documents.	The IESO posted responses to feedback on the Offers, Bids, & Data Inputs and Grid and Market Operations Integration detailed design documents on October 19 2020 and December 2 2020. There are no resulting changes to the referenced statement in the PD Calculation Engine document.

ID	Stakeholder	Feedback	IESO Response
826	OPG	On Page 48 the design states: “These past hourly production schedules will be equal to the output measured by telemetry less any production scheduled as part of an operating reserve activation”. Please explain why energy scheduled as part of an operating reserve activation (ORA) is subtracted from the output measured by telemetry. ORAs can be sustained for multiple intervals, and therefore have a material impact, especially for cascaded hydroelectric resources where ORAs affect forebay elevations at downstream stations. OPG is unsure why this explicitly excluding this output from the calculation engine. This treatment seems to contradict the inclusion of OR in the Max DEL constraint.	The activation of operating reserve is a manual process that does not consider multi-hour or multi-resource impacts. The activation is typically the result of a contingency and is an immediate, short term response. Offers for operating reserve, including those associated with cascade resources, represent flexible energy that is available to be used when activated. Operating reserve is activated for at most a single hour, generally less, and this reserve offer represents up to a single hour of energy at its resource at its respective offered price. Like today, this activation could occur on a downstream resource prior to receiving energy from an upstream resource or from an upstream resource whose downstream unit has the capability to receive the water without an urgent need to generate. Activations may also occur during lag time hours, if the operating reserve is offered in real time. Where cascade resource operating reserve activations cause conditions that certainly result in must run downstream constraints, market participants may use the hourly must run parameter or, if necessary, manual constraint requests to reflect must run conditions. For clarity, energy from operating reserve activations will be included when determining past energy produced up to the current hour in the current dispatch day to recognize the daily energy limit of a resource, or the shared daily energy limit of a set of resources.
827	OPG	[...] The PD Calculation Engine design appeared to omit how these hourly marginal loss factors would be transferred to the RT Calculation Engine. Please clarify which run of PD will be used to calculate and fix the hourly 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.	Please see the IESO's response to this comment under the Real-Time Calculation Engine feedback (ID #740), posted December 28 2020.

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828	OPG	Page 50 of the design states: “In cases where a resource provides updated offers that are priced lower than the respective reference levels, the updated offers will be used for the current PD calculation engine run.” i. Will the IESO notify market participants immediately when an offer has been mitigated? Offers are used by market participants to manage operational constraints, and prompt notification by the IESO of any changes will be necessary to allow appropriate action. ii. When a resource is mitigated, updated offers that are “lower than the respective reference levels” will be accepted in the current PD run. Resources pass the ex-ante conduct test, however, if offers are lower than the reference level plus the appropriate threshold. Since the calculation engine accepts offers above the reference level but below the threshold, should not market participants who were mitigated be allowed to submit updated offers that are also above the reference level but below the threshold? iii. Will resources that were mitigated be able to submit updated offer prices within the mandatory window?	The IESO will notify market participants when their offer has been subject to ex-ante mitigation. The IESO cannot allow offers above a given reference level during pre-dispatch once a particular offer of the resource has failed the conduct and impact tests. This would provide market participants with the knowledge that they have market power and the ability to exercise that market power within the applicable conduct and impact thresholds. Offer price changes that are lower than the applicable reference level may be requested within the mandatory window according to specific criteria. The criteria will be generally consistent with the existing criteria for allowing dispatch data revisions during the two-hour mandatory window - refer to Market Rules Chapter 7, Sections 3.3.6, 3.3.8, 3.3.11; and Market Manual 4.2, Appendix B.
829	OPG	[...] Please explain the process for determining the alternative station that will become the reference bus if Richview TS is out of service.	In the event that Richview transformer station (TS) is out of service, the calculation engine will automatically pick an alternative station in the largest island from a list of locations with strong connectivity to the rest of the system.
830	OPG	Page 57 of the design states: “When the pre-dispatch look-ahead period spans two dispatch days (i.e., the 20:00 EST to 23:00 EST PD calculation engine runs of the current dispatch day) certain daily dispatch data parameters will be evaluated across the entire look-ahead period using the daily dispatch data submitted for the second day. The daily dispatch data parameters that will be evaluated in this manner include: … • Lead time...” This may lead to under-utilization of NQS resources whose lead time increases from day to day. For example, a resource has a lead time of 2 hours in day 1, and a lead time of 4 hours in day two. The resource could technically synchronize between 20:00 EST and 23:00 EST on day 1. Given the language in section 3.5.5, however, the PD Calculation engine would not commit the resource, since only the 4-hour lead time parameter from day 2 would be considered. OPG recommends the IESO allows intra-day updates to daily dispatch data to mitigate this issue.	As described in Section 3.3.7.6 of the Grid and Market Operations Integration detailed design document, changes to daily dispatch data parameters such as Lead Time can be revised on an hourly basis during the Real-Time Market Restricted Window for Daily Dispatch Data. Revisions to data must include a reason for the change that meets specific criteria that will be defined in the market rules. The criteria will be generally consistent with the existing criteria for allowing dispatch data revisions during the two-hour mandatory window - refer to Market Rules Chapter 7, Sections 3.3.6, 3.3.8, 3.3.11; and Market Manual 4.2, Appendix B. Revisions to Lead Time to account for legitimate changes to lead times from the current dispatch day to the next is expected to satisfy the above criteria.

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831	OPG	The constraints overview section is comprehensive; however, it lacks any comparison of the differences between how DA, PD, and RT calculation engines manage constraints. For market transparency and certainty, it would be beneficial for the IESO to provide market participants a table outlining the differences in treatments of constraints in each of the calculation engines.	Thank you for the feedback. The IESO will take this feedback under consideration.
832	OPG	[...] Please provide details of how inadvertent payback transactions are optimized within the PD Calculation Engine and publish the PD schedules for inadvertent transactions.	In the current market, inadvertent payback is accounted for by adding to global demand when Ontario is paying back and subtracting from global demand when Ontario is being paid back. In the future market, inadvertent payback will be modeled as a firm transaction at the appropriate intertie zone to be scheduled by the PD calculation engine.
833	OPG	The constraint equations to prevent hydroelectric resources from being scheduled within a forbidden region (on page 75) 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 PD 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 remedy this existing deficiency in market design.	Please see the IESO's response to this comment under the Real-Time Calculation Engine feedback (ID #773), posted December 28 2020.
834	OPG	[...] In today's market, the ability to provide OR is assessed on an hourly basis and is independent of the DEL calculation. Hydroelectric operational constraints change hourly especially on cascade river systems where upstream/downstream discharges impact operating reserve availability.	Please see the IESO's response to a very similar comment under the DAM Calculation Engine feedback (ID #683), posted on December 2 2020.

ID	Stakeholder	Feedback	IESO Response
835	OPG	The IESO has incorporated both energy and OR into the maximum DEL and shared DEL constraint equations (on Pages 82 and 83) without regard for how this will impact hydroelectric scheduling, price setting eligibility, and efficiency in PD. The IESO should remove OR from these constraint equations and seek an alternate solution that assesses constraints required for OR on an hourly not daily basis. […] The IESO should not assume for the purposes of DEL calculations that the fuel associated with providing OR is used on an hourly basis. This is an overly conservative approach since on most days, hydroelectric stations receive very few operating reserve activations. One of the unintended consequences of limiting hydroelectric/ELR's ability to schedule OR would be that gas resources would be uneconomically picked up to fulfill the remaining OR requirement. The IESO should recognize that joint-optimization of energy and OR needs to be performed at the hourly level based on offer inputs by market participants which would consider quantities, offer prices, and an hourly limit to the combined schedule of energy and OR. […] The DEL constraints as written significantly reduce energy limited resources' ability to compete in the electricity markets and would increase costs to ratepayers. Hydroelectric resources would be very limited in their ability to be scheduled for energy and OR in PD, which could force the IESO to unnecessarily commit less economic, carbon emitting sources such NQS gas in PD instead. OPG strongly urges the IESO to re-evaluate these constraints.	The IESO understands the item described, has given due consideration, and can confirm that this constraint will not assume that the fuel associated with providing operating reserve is used on an hourly basis. For each resource, the max DEL constraint consists of 24 constraints, one for each hour. Each hour's constraint looks back at all the previous hours' energy schedules, e.g., hour ending (HE)5 constraint will add the energy scheduled in HE1-5. Each hour's constraint only considers the current hour's operating reserve schedule, e.g., HE5 constraint only considers OR scheduled in HE5. The intent of the constraint is to ensure that for each hour, there is enough energy remaining to meet an operating reserve activation in that hour considering the energy that was scheduled in the preceding hours. This is necessary to maintain reliability standards and must be considered when scheduling operating reserve from resources that are energy limited.
837	OPG	[…] Please provide an example of how Net Intertie Scheduling Limit (NISL) will solve in pre-dispatch. The NISL mechanism is flawed in today's market, which has resulted in the Market Surveillance Panel making recommendation 2-1 in their May 2014-October 2014 Report […] Also, what will the NISL be after Market Renewal? Will the current value of 700 MW remain in effect?	The IESO responded to a similar comment submitted as part of feedback on the Real-Time Calculation Engine detailed design document (ID #788). In that response the IESO stated that, "...by having a net intertie scheduling limit (NISL) pricing component in the locational marginal prices (LMPs), the resulting price signals will encourage a market response that is consistent with system needs." The current NISL value of 700 MW will not be changing as a result of the Market Renewal detailed design.
838	OPG	At the bottom of Page 88 (IESO Internal Transmission Limits), the first equation is for pre-contingency: The second equation is for post-contingency: Why are the signs before the energy generation item Injt,d different between the two equations (i.e. a "+" in the pre-contingency equation and a "-" in the one for post-contingency)?	Thank you for pointing this out. This will be corrected in V2 of the PD Calculation Engine detailed design document.

ID	Stakeholder	Feedback	IESO Response
839	OPG	Page 108 of the design states: "If a resource fails the price impact test, reference levels for the dispatch data parameters that failed the conduct test will be used in the subsequent runs of Pre-Dispatch Scheduling and Pre-Dispatch Pricing for that hour through to the real-time timeframe." If the market condition is changed (e.g., the resource does not fail in Price Impact Test due to demand and LMP decrease, or early return service of the transmission line from the outage), is the failed resource re-assessed in the future PD runs or does the mitigated (reference level) offer remain in PD calculations?	If a resource fails the conduct and impact tests in pre-dispatch then the applicable reference level will be used in the PD and real-time calculation engines until after the relevant dispatch hour(s) have passed. The IESO cannot allow offers above a given reference level during pre-dispatch once a particular offer of the resource has failed the conduct and impact tests. This would provide market participants with the knowledge that they have market power and the ability to exercise that market power within the applicable conduct and impact thresholds. Market participants will be able to update the resource's offer price to a level below the applicable reference level.
840	OPG	[...] The post-contingency thermal limits impact the congestion shadow price which is an important component of locational marginal price (LMP). Does IESO publish the post-contingency thermal limits in any public reports?	No, the IESO does not publish post-contingency thermal limits in any public reports.

ID	Stakeholder	Feedback	IESO Response
799	Power Advisory	Design and Application of LAP within IESO-Administered Markets As discussed during stakeholder engagement meetings working towards developing MRP High-Level Design (HLD) documents, the benefits to implementing a LAP sufficiently longer (i.e., up to 27 hours prior to the applicable RT dispatch hour) than the LAP applied in today's IAM (i.e., 1-hour) has clear efficiency and reliability benefits. […] the Consortium recommends that before applicable MRP Energy Detailed Design documents are finalized in 2021, IESO should host specific stakeholder engagement meetings to explain how all resources will be scheduled and dispatched based on pre-dispatch (PD) calculation engine decisions under various scenarios, including potential impacts on RTM prices. The above request is particularly needed because draft MRP detailed design proposes to implement scheduling/dispatch changes for some resources (e.g., applicable dispatchable hydroelectric generators) and some ramifications for other resources relative to scheduling/dispatch under today's IAM design and rules. […] The Consortium believes that the above points along with a LAP of up to 27 hours requires further analysis and stakeholder engagement meetings to inform MPs, stakeholders, and IESO whether MRP draft detailed design could result in material changes to scheduling, dispatching, price-setting, and/or settlements relative to IAM today. The above analysis and accompanied stakeholder engagement meetings will also inform applicable generators regarding potential implications to their contracts or rate-regulated framework. In turn, any potential implications to contracts and/or rate-regulated framework could then have causal impacts to exploiting (positively or negatively) proposed MRP design through potential future changes to offer behaviour and strategies.	Interconnections between design components, including new design features, have been considered throughout the design process. During the Implementation phase this work will include formal testing and analysis to ensure that the design as a whole 'hangs together' and functions as intended. The IESO remains committed to working collaboratively with stakeholders to further stakeholder understanding of the design, including providing background, clarification, rationale, and examples where needed. The IESO will aim to respond to requests that provide the greatest value to the broad stakeholder community, at the time and level of detail that provide the greatest efficacy. In terms of settlement outcome examples, the IESO will balance providing information that stakeholders can use to analyze how their individual strategies and business processes should change in the renewed market, without providing strategic advice to market participants.