OPG Comments for SSM Design Elements - 1/19/2018

IESO										OPG
Design Element ID	**Design Element**	**Identified Options**	**Slide Reference *Sept 21, 2017 material**	**Overview of Options**	**Common Practice**	**Other Considerations**	**Interdependent Elements**	**Preliminary Decision**	**Decision with Reasons**	**OPG Comments *Based on materials presented up to and including December 11, 2017**
SSM1	Energy Price - Congestion Component	1) Include Congestion in Pricing	Pages 7 - 15	A foundational choice for moving to SSM.	Option 1		N/A	1) Include Congestion in Pricing	Including the cost of congestion in the energy price is a foundational element of a SSM	OPG supports this decision as including congestion pricing is a foundational element of a SSM
SSM2	Energy Reference Price	1) Continue to use Richview (Status Quo) 2) Use another Location	Pages 8 - 23	• LMP Price does not depend on the choice of the reference location • Since market open, Richview has been used as thereference location without any adverse impacts on dispatch solutions	N/A		N/A	1) Continue to use Richview as the reference location.	Richview is close to the load centre and has a strong connection to the rest of the system. Richview has been used as the reference location for many years without any adverse impacts on dispatch solutions.	OPG supports this decision. OPG does not see a reason to deviate from the use of Richview as a reference location. Maintaining the status quo means this would also be the most cost effective option for all participants.
SSM3	Energy Price - Loss Component	1) Include cost of marginal losses in the dispatch but exclude from prices (Status Quo) 2) Exclude the cost of marginal losses from the dispatch 3) Include the cost of marginal losses in both the dispatch and prices	Pages 24 - 34	• Option 1 is complicated & will require maintaining a 2schedule system and CMSC • Option 2 will increase the cost of meeting load and require changes in the design & implementation of the constrained software schedule • Option 3 will minimize cost of meeting load without needfor CMSC, improve efficiency of market price signal andreduce uplift. It would also be consistent with the IESO's current constrained schedule	Option 3	Consideration whether to continue to use static loss factors or move to dynamic		3) Include the cost of marginal losses in boththe dispatch and prices.	Including losses in the dispatch of generation minimizes the cost of meeting load. It also eliminates the need for make-whole payments (like CMSC) due to losses pricing and is consistent with the goal of SSM (aligning prices with dispatch).	OPG supports this decision as the inclusion of loss component will reflect a more accurate price and reduce uplift. Where loss components are currently static within the dispatch optimization algorithm, OPG supports a review for updating these more frequently than annually but recommends the IESO consider the lessons learned (erractic dispatches) when dynamic losses were previously implemented. Moving to dynamic losses would add complexity and higher implementation costs.
SSM4	Ex Post vs. Ex Ante Pricing	1) Ex Post Pricing2) Ex Ante Pricing	Pages 35 - 43	•IESO currently uses a form of Ex Post (Option 1) in the unconstrained • Option 1 is complex to implement in a way to ensure it does not lead to pricing anomalies; past implementations have sent inefficient price signals during reserve shortages or ramp constrained periods • Option 2 is consistent with the IESO's current constrained schedule and avoids sending inefficient price signals duringreserve short or ramp constrained periods	Option 2			1) Ex-Ante pricing: use the same inputs that were used to determineschedule / dispatch.	Ex-ante pricing aligns pricing with dispatch (the goal of SSM). Virtually all ISOs have adopted Ex-ante pricing. Ex-ante pricing avoids problems identified by MISO and ISO-NE with inconsistencies between ex-post pricing and dispatch requiring increased make-whole payments.	OPG supports the decision for ex-ante pricing for pricing and dispatch aligment. Ex-ante pricing is the best practice approach adopted by other ISOs.

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SSM5	Intertie Congestion Pricing	1) Charge intertie transactions based on congestion charge in the constrained pre-dispatch and the price at the intertie in the real-time constrained schedule 2) Charge intertie transactions based on: • The real-time schedule price if there is no congestion • When export constrained -the higher of the nodal price in real-time or pre-dispatch • When import constrained -the lower of the nodal price in real-time or pre-dispatch	Pages 44 - 57	• Option 1 is similar to the status quo • Option 2 is similar to what has recently been used in the New York ISO	Approach varies among ISOs	There may be further changes required when the IESO investigates more frequent intertie scheduling or future coordinated transaction scheduling with neighbouring jurisdictions				IESO is recommending option 2 in which the intertie settlement price is the higher of the nodal price in Real-Time (RT) and Pre-dispatch (PD) (for export constrained) and the lower of the nodal price in RT and PD (for import constrained). The IESO's rationale for option 2 is for consistency of price treatment for interties and internal resources in constrained regions. In principle, OPG agrees treatment of interties and internal resources should be consistent, but believes option 2 does not achieve this. The IESO's comparison of internal generators and interties in its December 11 examples is not a valid comparison because: 1. Generators and loads are only subject to RT prices for settlement, not PD prices. 2. Generators and (some) loads are 5-minute dispatchable, where interties are committed and dispatched hourly. 3. Internal resources face different risks and different decision-making considerations than marketers. OPG is recommending further discussion on this element and integration in the discussions on related design decisions (FTRs, DAM)
SSM6	Supplier Pricing	1) Zonal Prices2) Nodal Prices	Pages 58 - 70	• Zonal pricing would mean retaining a certain amount of constrained on and off payments • Other ISOs that previously had zonal have moved to nodalpricing for suppliers. • Nodal pricing for Suppliers is used in all other SSM ISOs • Would improve market efficiency, reduce uplift andenable improvements such as a day-ahead market	Option 2			2) Nodal Pricing.	Nodal pricing allows for greatest efficiency gains through stronger alignment between price and dispatch. Nodal pricing will also better support operability by providing spot market incentives to provide flexibility	OPG supports nodal pricing for suppliers as it would provide the greatest efficiency gain from a pricing and dispatch perspective. Further information is required regarding: 1) How self-scheduling/intermittent generators would be paid. 2) Nodal point treatment for suppliers with injection points on both 115/230 kV 3) Cascading river systems; and 4) Impact on compliance aggregation 5) possible option for facilities within an aggregate to have a virtual node
SSM7	Operating Reserve Reference Price	1) Co-optimize energy and operating reserve	Pages 71 - 75	• Only one viable option which is also the status quo				1) Continue to jointlyoptimize Energy andOperating Reserve.	The IESO's current design is best practice for SSM markets.	OPG supports the decision to co-optimize energy and OR as this is best practice in other jurisdictions along with being the status quo.
SSM8	Operating Reserve Price -Congestion Component	1) Include Congestion in Pricing	Pages 76 - 84	• Only viable option for SSM	Option 1	This will provide a more efficient price signal for investments that would allow demand-side and storage resources to provide reserves in higher-priced regions		1) Include the cost of congestion in OperatingReserve Prices.	Including the cost of congestion in pricing is a foundational element of a SSM	OPG supports the decision to include congestion in OR pricing as it is a fundamental element of SSM and provides a more transparent pricing signal.

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SSM9	Constraint Violations	1) Apply current penalty prices in the constrained schedule, but relax violated constraints and determine settlement prices based on incremental energy and/or operatingreserve offer prices (status quo) 2) Use the same set of penalty prices for both dispatch andpricing a) Use current penalty prices b) Create a hierarchy of new penalty prices c) Create a demand curve for penalty prices 3) Apply current penalty prices in dispatch, but use a different set of penalty prices for settlement a) Create a hierarchy of new penalty prices b) Create a demand curve for penalty prices	Pages 85 - 94	Under all of the options, OR and Energy prices would continue to be capped at $2,000/MWh. • ISOs operating single schedule markets have evolved awayfrom using arbitrarily large penalty prices and towards choosing penalty values that are consistent with the cost ("reliability value") of actions the ISO would take to resolve those conditions	• Most ISOs have moved toward usingtransmission andoperating reserve demand curves in real-time dispatch	• A key driver is to ensure that operators don't have to manuallymake these decisions; the prices need to be set correctly to ensure the software makes the right commitment decisions. • ISOs moving toward penaltyvalues that more closely reflect thecost or 'reliability value' of controlactions.				In general, OPG believes energy and OR prices should be reflective of true costs rather than relying on uplifts. OPG supports market prices that reflect the "reliability value" of constraint violations and should not be capped at $2000/MWh. OPG agrees **offer** prices should be capped at $2000 (unless marginal costs can be proven to exceed this) Would the IESO confirm: i) whether other jurisdictions cap market prices ii) whether the magnitude of the penalty values used by other ISOs are consistent with "reliability value"? iii) Would a $2000/MWh cap on energy and OR prices prohibit a value that adequately represents the reliability value? OPG supports the IESO's decision to assess each constraint violation individually for the appropriate option. OPG is interested in **all** violation types.
SSM10	Out-of-market Operator Actions	1) Control actions are priced at maximum market price ($2,000) or some other level for one or more of thefollowing: a) Voltage reductions b) Curtailment of exports for adequacy c) Scheduling of emergency imports 2) Control actions are not priced	Pages 95 - 107	Option 1 a,b&c • Would provide a stronger price for generation and load resources to respond • Would require some changes in constrained schedule or implementation of a 'pricing pass' • Would be most consistent with the current practice usedby the IESO Option 2 • Would not provide additional signal for generation andload to respond • Would not require any changes in constrained schedule or introduction of a 'pricing pass' • These actions are rarely used, but the value of load reductions for the additional price signal may be very high	Varies		Outcomes of the options in design element 9 - Constraint Violation pricing - may affect the choices made when pricing out-of-market operator actions			Similar to SSM9, OPG believes actions need to be evaluated for their true cost to minimize uplifts and should not be limited by a price cap. On slide 94 of the December 11 presentation, the IESO presented a list of Out of Market Operator Actions and their respective price impacts in the unconstrained sequence. While the IESO's recommendation was to assess each control action, it also stated on slide 96 that it would likely keep status quo for SSM. OPG does not agree that the list for the unconstrained sequence currently used today is appropriate for a constrained SSM sequence and is suggesting the decision be reassessed. Additionally, OPG would ask the IESO to provide the list of out-of-market actions used for the current constrained sequence. ?

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SSM11	Multi-Interval Optimization	1) Use MIO to determine schedules but use single intervaloptimization for prices (similar to status quo)2) Use MIO to determine schedules and prices	Pages 108 - 115	Option 1 • Similar to current design but SSM would take actual ramp rates, transmission congestion and minimum load blocks into account when calculating prices • Potential for inconsistencies between dispatch and prices. Option 2 • Reduced potential for inconsistencies between dispatch and prices.	Varies (not all jurisdictions have implemented MIO)			2) Use multiple intervaloptimization to determine schedules and prices.	Using MIO for both pricing and dispatch improves alignment between the two, reducing the frequency of required make-whole payments.Is consistent with other jurisdictions using multi-interval optimization.	OPG supports the decision to use Multi-Interval Optimization (MIO) to determine schedules and prices for pricing and dispatch alignment. Furthermore, OPG would ask the IESO to consider the possibility of either expanding MIO capabilities to optimize for hydroelectric dispatch limitations or create a separate hydro dispatch optimization module. A reduced number of dispatches would minimize maintenance costs for resources and respect operation/regulatory restrictions.
SSM12	Price-Setting Eligibility/Operating Restrictions	1) Do not allow any resources' restricted MW's (e.g. minimum loading point) to set or impact prices (status quo in the constrained schedule). 2) Allow fast start online resources' restricted MW's to set or impact price.	Pages 116 - 123	Option 1 • Would not require changes in prices determined by theconstrained schedule. • Could at times set prices that would be inconsistent with the dispatch of fast starting resources with MLPs (Ontario currently has few such resources) Option 2 • Would produce marginal prices more in line with actualdispatch of fast-starting resources with MLPs in real-time • Would require changes in how prices are determined bythe constrained schedule when units with operatingrestrictions are marginal	NYISO allows fast-start gas turbines to set price, so long as they are marginal and not simply online because of minimum run-time considerations					Based on simplicity and the minimal impact on price misalignment as presented in the data at the December 11 meeting, OPG supports the IESO's decision to proceed with option 1. As an aside, would the IESO indicate whether restricted MW for hydro units was considered in its decision? Also, were ramp limited MW considered restricted MW?
SSM13	Mitigation process	1) Pivotal Supplier Test (offer/bid is subject to mitigation if it is part of supplier capacity that is pivotal in resolving a binding constraint - measure of amount of competition) 2) Conduct and Impact Test (offer/bid is subject to mitigation if it exceeds competitive reference level, and has a market impact by raising theclearing prices).	Pages 3 - 17	Method in which to apply mitigation: Option 1 • Depends on complicated approximations in order to identify pivotal supply associated with a constraint • May not capture all of the binding constraints ex-ante - potential for under mitigation Option2 • Captures comparatively more of the potential market power scenarios • If market impact is identified, then mitigation is applied to all those whose offers exceeded the conduct threshold • Mitigation process requires significant processing time (needs to resolve the dispatch up to three times)	VariesOption 1 - PJM, CAISOOption 2 - NYSIO, ISONE, MISO, SPP	• A further considerationassociated with the PivotalSupplier Test is whether to test for one, two or three pivotal suppliers.		2) A conduct and impact test.	A conduct and impact test avoids the need for complex assumptions in areas such as offers of competing suppliers. It does not depend on detecting all binding transmission constraints prior to real-time. Mitigation is more directly tied to (estimate of) the actual exercise of market power.	OPG supports proceeding with option 2 (Conduct and Impact test) but would like further clarification on its timing of application (see SSM 14 comments below) - On slide 27 of the December 11, 2017 presentation, it says US ISOs generally identify a binding transmission constraint in order to apply ex-ante mitigation. Slide 37 further indicates MISO and SPP do not apply a conduct test absent a binding constraint. This would appear to be a simple and logical approach that would limit over-mitigation under a conduct and impact regime. - Slide 17 of the IESO's November 13 presentation states that one downside to the Conduct and Impact test is the potential for offers of a large supplier to trigger mitigation applicable to all suppliers within the region who had also failed the conduct test. Would the IESO provide further detail on how this region is identified?

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SSM14	Timing of Application	1) Ex-Ante (before the fact) market power mitigation	Pages 18 -19	• Because the exercise of market power in a SSM can affect market prices, mitigation needs to be done before market prices are determined. • After the fact mitigation and the subsequent resettling of market prices would be complicated and disruptive	Ex-Ante	• While incremental bid/offers are subject to ex-ante mitigation, mitigation of start-up costs, minimum load costs, and/or restrictive operating parameters could potentially be performed ex-post (impacts are limited to uplift which can be dealt with after-the- fact)		1) Apply market power mitigation ex-ante (before the fact).	Because the exercise of market power in a SSM can affect market prices, mitigation needs to be done before market prices are determined	-Slide 19 of the November 13 presentation states applying mitigation on an ex-ante basis is a foundational feature of SSM, yet Slide 37 of the December 11 materials state NYISO performs mitigation ex-post. What is the reason NYISO does not test for pivotality or a binding constraint and mitigates ex-post if ex-post mitigation resettlement is deemed to be "complicated and disruptive"? - under current market rules where mitigation occurs ex-post, Market Participants are allowed "reasonable opportunity" to provide representation of price justification. With Ex-Ante mitigation, the Notice of Disagreement process should be sufficiently long to accomodate exhaustive review for participants to provide representation.
SSM15	Reference levels	1) Apply principles used in today's mitigation, in order to develop reference prices.2) - Develop new principles that develop reference prices used for mitigation.	Pages 20 - 31	Mitigation process needs reference offer prices that are an estimation of resource costs (including opportunity costs). More complicated for ex-ante mitigation, as these need to be calculated before all costs are known.				1) Apply the principles used today to determinereference prices for market power mitigationin an SSM market.	The principles that govern how the current regime determines reference prices and settlement adjustments are consistent with those underpinning reference prices under ex-ante mitigation regimes. Moving to ex-ante mitigation does not render the general approach adopted today unviable. However, ex-ante mitigation will require a change in methodology for determining reference levels.	- Similar to CAISO and PJM as shown in the table on slide 52 of the December 11 presentation, OPG supports the ability to rank options for reference price determination. OPG believes this should be applied for each individual resource for a predetermined effective period. OPG would appreciate greater details on how CAISO and PJM implement this. -For Enhanced Real Time Unit Commitment (ERUC) (and Day-ahead) how do other jurisdictions allow Market Participants to identify unusual conditions that may cause a resource's offer price and/or physical attributes to be different from the calculated reference values? eg.) seasonally changing hydro conditons, combined cycle station operating in simple cycle mode, testing units, units with dual fuel options, equipment problems resulting in abnormal ramp rates, etc. Do other jurisdictions allow for these situations to be identified prior to mitigation therefore preventing unwarranted mitigation? If a participant that has been mitigated is able to justify an offer price greater than the reference price (after the fact), please confirm whether a resettlement would occur for only the single participant or for all participants within the mitigation 'region'

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SSM16	Pricing for loads	1)All loads pay the nodal price at their location. Prices include the marginal cost of losses and congestion. 2)All loads pay the zonal price, at the zone associated with their location. Prices include the marginal cost of losses and congestion. 3)All loads pay the province wide uniform price. Prices include the marginal cost of losses and congestion. 4)Dispatchable loads pay the nodal price, while non-dispatchable loads pay the zonal price. Prices include themarginal cost of losses and congestion. 5)Dispatchable loads pay the nodal price, while non-dispatchable loads pay the uniform price. Prices include themarginal cost of losses and congestion. 6)Dispatchable loads pay the zonal price, while non-dispatchable loads pay the uniform price. Prices include themarginal cost of losses and congestion. 7)All loads pay the province wide uniform price. Prices include the average cost of losses and congestion.	Pages 32 - 72	Load pricing options are based on three fundamental questions: 1.) Does the load price include the marginal or average cost of congestion and losses? • will decide if congestion and loss surpluses which can beused to fund FTRs or a uplift disbursement 2.) Will dispatchable and non-dispatchable loads be settledat the same level of granularity? (nodal, zonal, uniform)? • if different, may require a incentive mechanism to maintain amount of DL 3.) What is the applicable pricing granularity to the price (nodal, zonal or uniform)?	Variants of Option 4 seem to be the most common					Further discussion is required
SSM17	Financial transmission rights	Option 1 - Full FTR Allocation: FTRs allocated to all loads to address incentive issue of dispatchable load (potentially paying a higher price) and to offset the impact of non-uniform pricing for all load. Option 2 - Alternative (non-FTR) Mechanism: Payments and charges to loads so that the sum of the payment and their energy price is approximately uniform Option 3 - No FTRs: No FTRs or other payment mechanism to address incentive or cost impact of change to non-uniform pricing Option 4 - FTRs allocated to dispatchable loads (and possibly to price responsive loads) in locations with average LMPs higher than average zonal price paid by non-dispatchable load Option 5 - FTRs allocated to all dispatchable load (and possibly to all price responsive loads) Option 6 - Payments to dispatchable loads (and possibly to price responsive loads) in locations with average LMPs higher than zonal price (links to load pricing Options 4, 5 and 6)	Pages 32 - 72	Options are introduced to address incentive or efficiency issues as a result of a particular load pricing option. The issues include: 1) Incentive issue - dispatchable load choosing to become non-dispatchable in order to pay a lower zonal price (than its nodal price) 2) Efficiency issue - dispatchable load paying a zonal or uniform price may incur actual or opportunity costs while following dispatch instructions 3) Incentive issue - for all loads in moving away fromuniform pricing	Non-traditional application of FTRs (typical application is to provide node to node congestion hedge)	• Choice needs to be an approximation that is independent of actual consumption in order to preserve the marginal incentives at the location/zone	• Choices are dependant on which load pricing option is chosen (will varythe incentive or efficiency issues that need to beaddressed)			To be discussed together with load pricing

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SSM18	Make whole payments	1) Provide make whole payments for constrained up/down scenarios 2) Provide make whole payments only for constrained upscenarios	Pages 73 - 76	Options address compensation that may be required when a resources' dispatch is not in line with the prices at its location. A resource may be constrained up to provide ramp in a later interval (potentially incurring an operating loss) OR Constrained down to allow, for example, a fast starting gas-fired unit to come online (need to respect the minimum load of the gas unit) - potentially incurring an opportunity loss	Option 1			1) Include make whole payments in the designfor constrained up andconstrained down suppliers.	Including make whole payments to both constrained up and constrained down suppliers creates appropriate incentives for resources to follow the IESO dispatch instruction, resulting in greater operational certainty for the IESO. In general, make whole payments will no longer occur because of transmission congestion. Also, make-whole payments are likely offset by OR revenues, where applicable.	OPG agrees make whole payments should be for both constrained up and down scenarios to create appropriate incentives to follow dispatch.
SSM19	Uplift recovery	1) Distribution of congestion rents and marginal loss surplus will be based on the per MWh of actualwithdrawals by internal loads 2) Distribution of congestion rents and marginal loss surplus will be based on the per MWh of actualwithdrawals by internal loads and exports	Pages 77 - 80	New types of payments (associated with congestion rents and losses) will need to be distributed to (or recovered from) market participants.	Varies					OPG supports option 2 as exports have an impact on loss and congestion. Notwithstanding, while this item only speaks to congestion rents and marginal loss surplus, OPG believes uplifts should be minimized wherever possible to have appropriate costs reflected in energy/OR prices. While energy costs can be potentially hedged, uplift costs cannot.