EB-2024-0331

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Electricity Act, 1998,* S.O. 1998, c. 35, (Schedule. B);

AND IN THE MATTER OF an Application by Capital Power Corporation, Thorold CoGen L.P., Portlands Energy Centre L.P. dba Atura Power, St. Clair Power L.P., TransAlta (SC) L.P. (collectively, the "NQS Generation Group") for Review of Amendments to the Independent Electricity System Operator Market Rules.

COMPENDIUM OF THE SCHOOL ENERGY COALITION
(IESO Witness Panel)

Shepherd Rubenstein P.C.
2200 Yonge Street, Suite 1302
Toronto, Ontario M4S 2C6

Mark Rubenstein
Tel: 647-483-0113
Fax: 416-483-3305

Counsel for the School Energy Coalition

A. NATURE OF THE ORDER OR DECISION APPLIED FOR

1. On October 18, 2024, the Independent Electricity System Operator's ("**IESO**") Board of Directors approved a package of amendments ("**MRP Amendments**"), known as "market rule amendments MR-00481-R00-R13", to the full suite of Ontario Electricity Market Rules ("**Market Rules**") which were required to operationalize the Market Renewal Program ("**MRP**").

2. Capital Power Corporation, Thorold CoGen L.P., Portlands Energy Centre L.P., dba Atura Power, St. Clair Power L.P., TransAlta (SC) L.P. (collectively the "**NQS Generation Group**") apply to the Ontario Energy Board ("**OEB**") for:

    a. review of the IESO's MRP Amendments of the Market Rules under section 33(4) of the *Electricity Act, 1998*;

    b. an order revoking the MRP Amendments and referring them back to the IESO for further consideration on the basis the MRP Amendments are inconsistent with the purposes of the *Electricity Act, 1998* and unjustly discriminates against a market participant or class of market participants under section 33(9) of the *Electricity Act, 1998*;

    c. that the OEB exercise its discretion under section 21 of the *Ontario Energy Board Act, 1998* to direct the IESO to provide more fulsome disclosure relating to the MRP Amendments, which disclosures would be specifically relevant to the matters in dispute in this Application (see Schedule A);

    d. a Procedural Order that allows the NQS Generation Group to file evidence in support of this Application after a reasonable period of time following the IESO's mandatory disclosure information specified under section 6.3 of its Licence EI-2013-0066 and any OEB direction for additional IESO disclosure under section 21 of the *Ontario Energy Board Act, 1998*; and

    e. such further and other relief as the NQS Generation Group may request and the OEB may grant.

3. The NQS Generation Group files this Application in accordance with section 16 of the OEB's *Rules of Practice and Procedure* issued on March 6, 2024.

4. The NQS Generation Group reserves the right to amend or supplement this Application with facts, grounds, submissions, and evidence following receipt of the IESO's mandatory disclosure under section 6.3 of its Licence EI-2013-0066 and any OEB direction for additional IESO disclosure under section 21 of the *Ontario Energy Board Act, 1998*.

B. STATEMENT OF FACTS

5. The NQS Generation Group, and their affiliates, represent a class of market participants that operate non-quick start ("**NQS**") gas-fired generation facilities in Ontario. These facilities operate pursuant to IESO Market Rules and various forms of contractual agreements (collectively, the "**Deemed Dispatch Agreements**") with the IESO.

6. There are currently 9,723 MW of natural gas-fired generation in Ontario representing 25% of Ontario's total supply mix of 38,264 MW. Natural gas-fired generation plays an important role in supporting grid reliability in Ontario, according to both the IESO and the provincial government. Provincial energy policy documents have repeatedly highlighted the importance of natural gas-fired generation and have directed the IESO to procure incremental capacity in order to maintain reliability in the face of forecasts for growing electricity demand. Natural gas-fired generation can provide continuous energy throughout the year, under all weather conditions. Natural gas-fired generation units can also be ramped up and down to respond to changes in demand or the availability of other generation resources, such as intermittent renewable suppliers like wind and solar generators. Additionally, it provides reliability services to the grid operator to stabilize voltages and frequencies on the transmission grid, among other benefits.

7. The MRP Amendments implement a comprehensive suite of changes to the IESO-Administered Markets ("**IAM**"), including:

a. The introduction of a single schedule market (including the implementation of Locational Marginal Prices (**"LMPs"**)),[1] and the corresponding elimination of the Congestion Management Settlement Credit ("**CMSC**") regime;

b. The introduction of a binding Day-Ahead Market ("**DAM**"),[2] replacing the current Day-Ahead Commitment Process ("**DACP**"), that will include financially binding commitment and dispatch schedules and incorporate numerous financial and non-financial parameters that are not considered in the current market design and rules that predominantly commits and dispatches NQS generators today;[3] and

c. The introduction of an Enhanced Real-Time Unit Commitment ("**ERUC**"),[4] replacing the current pre-dispatch commitment process. ERUC includes without limitation:

   i. The replacement in real-time of a single energy offer (incremental energy cost) with the introduction of three-part offer structure (start-up cost, speed-no-load cost, and incremental energy cost), as well as financially binding prices in the DAM based on three-part offers (where such financially binding prices do not exist today);

   ii. The replacement of a simpler optimization algorithm under the current market with a new, more complex market optimization algorithm (that optimizes over multiple hours, and as between day-ahead and real-time schedules); and

   iii. The replacement of the Real-Time Generator Cost Guarantee ("**RT-GCG**") program, with the substantially altered Real-Time Generator Offer

[1] https://www.ieso.ca/Market-Renewal/Stakeholder-Engagements/Market-Renewal-Single-Schedule-Market

[2] https://www.ieso.ca/Market-Renewal/Stakeholder-Engagements/Market-Renewal-Day-Ahead-Market

[3] In the renewed market, the majority of dispatch schedules, including imports and exports, will be determined day-ahead with the real-time market intended to be a balancing market to manage demand forecast errors and upset in supply.

[44] https://www.ieso.ca/Market-Renewal/Stakeholder-Engagements/Market-Renewal-Enhanced-Real-Time-Unit-Commitment

Guarantee (“**RT-GOG**”) program resulting in significant negative financial impacts related to wholesale market revenues for NQS Generation Group.

8. Following MRP, the IESO’s new day-ahead calculation engine will maximize the gains from trade over the subsequent 24- hour period given market participant offers and bids, resource constraints and the reliability needs of the system. At times, the most efficient and reliable schedule for the system as a whole can result in some facilities being scheduled at an implied loss, or not being scheduled when they are economic on an incremental energy basis. A facility could be scheduled in the DAM at a loss in order to meet all system constraints for reliability, for example, to avoid violation of a transmission limit. In short, the complexity of determining commitment and dispatch – which will include millions of different data points, both economic and physical – is expected to result in outcomes that will not clearly be based on economic incremental energy offers.

9. The MRP Amendments will harm the NQS Generation Group in the following ways (all else being equal):

    a. NQS Generators will receive less scheduled commitments following MRP due to the calculation engines included in the MRP Amendments optimizing across the subsequent hours prior to real-time dispatch and incorporating non-incremental energy costs. These changes are likely to result in NQS Generators not being committed and dispatched, at times, even though they are economic on an incremental energy basis;

    b. NQS Generators will receive lower GOG payments, whether committed through DAM or ERUC, than the previous RT-GCG payments. The current settlement design for the RT-GCG program incorporates less potential wholesale market revenues than is contemplated under theGOG settlement process included in the MRP Amendments. As a result, the same operating profile with the same energy prices, could result in different compensation levels for NQS generators pre- and post-MRP, with the Market Renewal result being economically worse;

c. NQS Generators will receive lower wholesale and operating reserve ("**OR**") revenues in periods where Market Power Mitigation is applied than under the current Market Power Mitigation Framework. The current wholesale market does not include *ex ante* mitigation of financial and non-financial parameters. As part of the MRP Amendments, Market Power Mitigation may potentially lower energy offers and other parameters across the entire wholesale market, which will result in lower revenues (all else being equal) that the current market design; and

d. NQS Generators may receive lower revenues in the form of make-whole payments and the LMP than previous revenues from CMSC payments plus the uniform market clearing price under the IAM. Under the current Market Rules, CMSC payments are made for a variety of reasons beyond what is contemplated for make-whole payments under MRP Amendments, including as a result, for example, of the 3-times ramp rate that is included in the unconstrained schedule (i.e. market schedule).

10. The combination of the harms described in the previous paragraph resulting from the discriminatory MRP Amendments will result in lower total revenues from the IAMthan under the current Market Rules for NQS Generators. Other classes of market participants are not experiencing harm from the MRP Amendments to the same degree as NQS Generators, if at all. The MRP Amendments fundamentally change the financial interaction of NQS Generators with the IAM. While the harms experienced by NQS Generators may be addressed through various interrelated means (such as contract changes, Market Rule changes, and provincial policy, among other options) the fact is that the harms are resulting from the MRP Amendments as currently proposed. If the MRP Amendments are revoked, the harms experienced by NQS Generators ceases to be a concern.

The Relevance of the Deemed Dispatch Agreements to the Amendments

11. These MRP Amendments must also be read in the context of both the IESO's Resource Adequacy Framework and the contract design for NQS Generators. In terms of Resource Adequacy, the IESO explains that this is its "*long-term competitive strategy to acquire*

resources while balancing ratepayer and supplier risks and recognizing the unique characteristics and contributions of different resource types."[5] In terms of the contract, all of the NQS Generators' Deemed Dispatch Agreements account for the current Market Rules and for revenues earned in the IAM as it is currently designed.

12. The Resource Adequacy Framework combines a suite of short-term, medium term and long-term tools that the IESO uses to meet its forecasted capacity and reliability needs. In the short term, the IESO has planned regular capacity auctions (under the IESO Market Rules) which are used to procure capacity and improve resource reliability and market performance without locking into long-term commitments. In the medium term, capacity, energy, and other operational requirements are being procured, *inter alia*, through competitive Requests for Proposals ("RFPs") that result in contracts with a medium duration commitment period (e.g., 5 years). Over the long-term, the IESO facilitates investment in new builds or major upgrades to existing resources through competitive RFPs that result in longer-term contracts.

13. Nearly all generation assets in the IAM operate in tandem with both the Market Rules and contracts related to the assets. In prior cases, these two components have diverged and created conflict and, in some cases, resulted in applications to the OEB to review the proposed amendments to the Market Rules (e.g., EB-2007-0040, EB-2013-0010, and EB-2019-0242). In short, neither the Market Rules or the contracts (or the design of the contracts) operate in isolation, both are intertwined.

14. Many of these medium and long-term contractual arrangements are designed to operate in and with the IAM. To properly understand the impact of the MRP Amendments on a specific market participant, or certain classes of market participants, that have such a contract, it is essential to understand:

    a. How the contract, together with the IAM, impacted the market participant, or class of market participants, prior to the implementation of the MRP Amendments; and

[5] https://www.ieso.ca/Sector-Participants/Planning-and-Forecasting/Resource-Adequacy-Framework

b. How the contract, together with the IAM, impacted the market participant, or class of market participants, after the implementation of the MRP Amendments.

15. The IESO has expressly acknowledged the implications of the MRP Amendments to electricity supply contracts,[6] and has "*committed to working with electricity supply contract counterparties that are market participants to understand contract implications and address any changes throughout the design of the Market Renewal Program (MRP).*" This statement by the IESO implicitly acknowledges that the Market Rules and electricity supply contracts are not mutually exclusive.

16. The IESO has stated that it is "…not an objective of the IESO to extract financial value from contracts by the way of MRP … The IESO intends to maintain the allocation of risk and reward that has been established by the contracts to the greatest extent possible, including, where applicable, the impacts of market rule changes."[7] However, there is a misalignment between the IESO's stated intention and its actions in the MRP Amendments.

17. The NQS Generation Group is most directly impacted by what the IESO has called its "Clean Energy Supply (CES) Contracts" work-stream, pursuant to which between September 2019 and June 2024 the IESO has held a number of stakeholder engagement sessions and proposed a series of term sheets, the most recent of which was published in June 2024 and provides, in part (the "**Term Sheet**"):

> "*Based on the Detailed Design Documents and the provisional IESO Market Rule amendments, the IESO anticipates that a requirement for a Replacement Price and Replacement Provisions will be triggered under (i) Section 1.7 of the Contract, addressing the opening of a Day Ahead Energy Forward Market and (ii) Section 1.8 of the Contract, addressing the occurrence of a Price Evolution Event (namely the implementation of Locational Marginal Pricing).*"
>
> *[…]*

[6] https://www.ieso.ca/Market-Renewal/Background/MRP-implications-to-electricity-supply-contracts

[7] *Supra footnote* ***Error! Bookmark not defined.***.

"In entering into the MRP Amending Agreements, the Parties will agree that the Replacement Price and Replacement Provisions satisfy any and all obligations each Party has to the other under the applicable Contract in connection with the IESO Market Rule amendments implementing the energy stream of MRP as of the date of the MRP Amending Agreement."

18. The MRP Amendments, when considered together with the IESO's proposed Term Sheet amendments, are unjustly discriminatory and inconsistent with Subsections 1(d), (g) and (i) the *Electricity Act, 1998*. The MRP Amendments have fundamentally failed to address the harms caused by, among others, the replacement of the RT-GCG program, the introduction of three-part offers regarding the commitment and dispatch of NQS Generators and how LMPs will be determined, and the significantly more complex optimization engine in both the DAM and the Real-Time Market (**"RTM"**) that is expected to result in less commitment and dispatch and lower commitment payments, all else being equal. These harms were addressed in more detail previously. The NQS Generation Group has communicated its concerns with the MRP Amendments to the IESO and to-date those concerns have not been sufficiently addressed to satisfy the legal test under section 33(9) of the *Electricity Act, 1998*.

The Deemed Dispatch Model Contained in the Deemed Dispatch Agreements and the Interaction with the MRP Amendments

19. Each of the Deemed Dispatch Agreements at issue in this Application utilize a deemed dispatch, or imputed net revenue, model to calculate contractual settlements.

    One way to understand the contractual settlement process is to assume that, for contractual purposes, the IESO has created a "virtual power plant". The contract imputes net revenue to this "virtual power plant" based on assumed and modelled behaviours in, and outcomes from, the IAM.

20. Prior to the MRP Amendments, to the extent the physical generator operates in a manner consistent with the assumed and modelled behaviour of the "virtual power plant", the net revenues the generator receives from the IAM would largely mirror the imputed net revenues

under the contract. In short, the current Market Rules and the Deemed Dispatch Agreements were aligned – particularly in relation to the RT-GCG program – in how they included commitment and dispatch in the wholesale market, which allowed NQS Generators to more accurately operate their facilities to align with the contract design and actual revenues earned in the wholesale market.

21. Similarly, prior to the MRP Amendments, to the extent the physical generator does not operate in a manner consistent with the assumed and modelled behaviour of the "virtual power plant", the net revenues from the IAM may be less than (or greater than) the imputed net revenues under the contract. Under the MRP Amendments, the link between how the physical generator is operated, committed and dispatched and how it's modelled under the Deemed Dispatch Agreements, is broken. The link is being broken by, and the financial impact is being incurred, as a result of the MRP Amendments.

22. The differences between the imputed net revenue under the contract and actual net revenue earned under the IAM is fundamental to understanding the unjustly discriminatory nature of the MRP Amendments.

23. As a consequence of the harms laid out in paragraph 9 and the broken link described in paragraph 21, following the MRP Amendments (and as will be more fully demonstrated in evidence) the NQS Generation Group is expected to suffer harm first due to changes in how they are committed, dispatch and settled in the IAM, and second due to the divergence as between those IAM factors and treatment under their existing Deemed Dispatch Agreements (even after assuming all of the changes proposed in the IESO's form of Term Sheet are made) including, without limitation:

    a. Commitments under MRP will be determined by the economics of a generator's three-part offer for subsequent hours prior to real-time dispatch, whereas the Deemed Dispatch Agreements continue to determine assumed operations based on incremental energy offers only on an hour-by-hour basis. As a result, NQS Generators will be rendered less competitive and be committed less under MRP than they are today (all else being equal). Despite this market impact, there is no commensurate reduction in assumed competitiveness or commitment under the Deemed Dispatch Agreements, resulting in a reduction in actual net IAM revenues relative to imputed net contract revenues – economically harming a class of market participants.

b. the marginal generation unit will be published (i.e., LMPs), which provides insufficient information for a NQS Generator to assess why it did, or did not, receive a commitment. This is not the case prior to MRP, where published wholesale energy prices are sufficient to understand why a NQS Generator received or didn't receive a commitment (because of the RT-GCG program). Following MRP, the increased complexity of the commitment process makes it a "black box" that will not allow NQS Generators to assess why their facilities failed to receive a commitment despite appearing economic (even after the fact).

c. Commitments under MRP will incorporate the impact of physical constraints elsewhere on the grid, whereas the Deemed Dispatch Agreement will consider no such constraints, only the purported after-the-fact economics. By incorporating these constraints under MRP, NQS Generators may fail to receive a commitment, despite appearing economic after-the-fact. This will result in a reduction in actual net IAM revenues relative to assumed net contract revenues.

d. The RT-GCG program is the primary means of a NQS generator receiving a commitment in the current market, serving as a critical hedging tool to deemed operation. MRP will eliminate this program and commit NQS generators via the DAM and ERUC, neither of which provide the same hedging opportunities as the RT-GCG program.

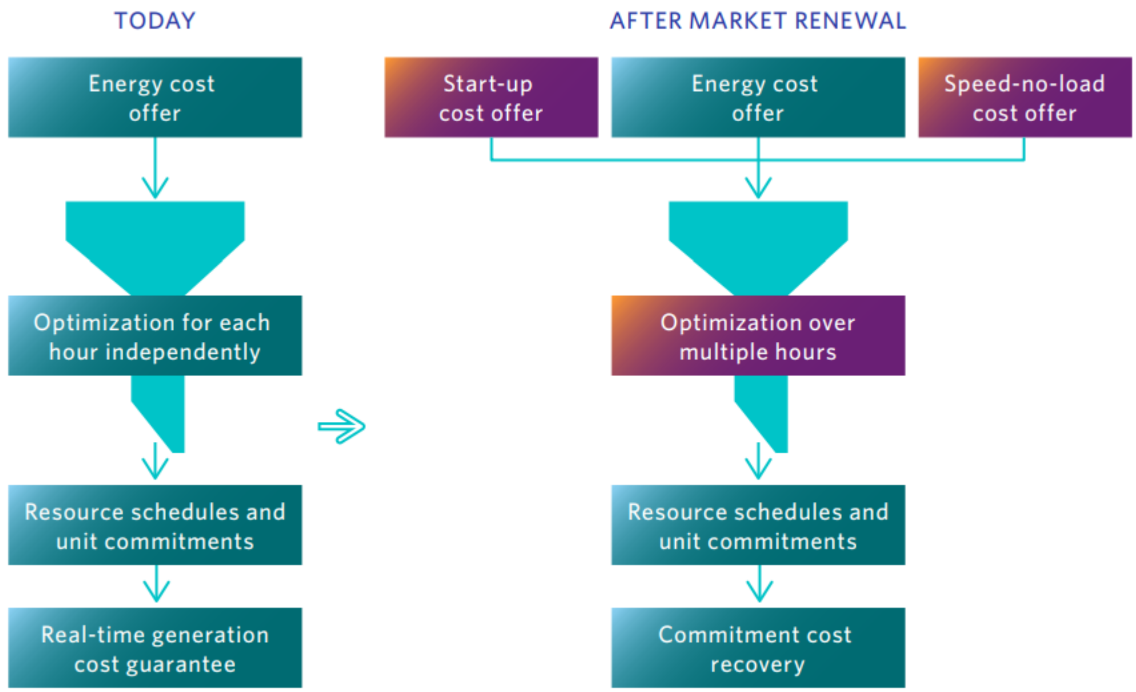
e. The current pricing algorithm uses a 3x ramp rate and an unconstrained dispatch algorithm to dampen price volatility and ultimately lower Hourly Ontario Energy Price ("**HOEP**") levels. Under MRP, a 1x ramp rate and a constrained dispatch algorithm will be used which will add volatility to LMPs relative to HOEP. More volatility increases the risk that generation units are running when it is uneconomical to do so.

f. The IESO's detailed design documents (available at the links provided in footnotes 1, 2 and 4 above) are clear that optimizing over an entire day may result in commitment that may not be strictly economic in nature. The existing Deemed Dispatch Agreements (even after assuming all of the changes proposed in the IESO's form of Term Sheet are made) do not optimize over an entire day.

g. With three part offers, only the incremental energy offer is eligible to set price. This does not reflect the actual cost to produce energy and could result in the reduction of actual net revenues for all suppliers.

h. Elimination of the double trigger for imputed start-up. Under the current contract, both the Pre-Dispatch (PD)-3 and real-time wholesale energy price (i.e., HOEP) needs to exceed the Variable Energy Cost (VEC) for an hour to count as an imputed start-up hour. Under IESO's the Term Sheet, the double trigger has been replaced with a single test, whether the DAM price exceeds the VEC. Reducing the threshold for an imputed start up hour from two tests, to a single test, increases the likelihood of an imputed start up hour, all else being equal. Note that the double trigger criteria for shutdown remains, requiring multiple hours where the market prices are below VEC. The net effect of these two facts is to make imputed start-ups more frequent while maintaining the same conditions for imputed shutdowns. This, on its own, will result in more imputed production hours under the Term Sheet relative to the current contract, all else being equal, and more imputed net revenue than actual net market revenue.

Figure 1: MRP Changes to the MRP Unit Commitment Process



Alternatives to the Deemed Dispatch Model

24. To the best of the knowledge and belief of the NQS Generation Group, Ontario is the only jurisdiction in Canada or the United States that has utilized a unique "deemed dispatch model" for gas-fired generators.

25. Consequently, it is perhaps unsurprising that there are viable alternatives to the deemed dispatch model that could be used by the IESO to incent performance and settle gas-fired generators. One such example would be to adopt elements of capacity style contracts more commonly used across North America and which the IESO successfully used for its LT1 RFP and eLT1 RFP procurement processes. The IESO is currently proposing to use a capacity style contract again for the capacity stream of its proposed LT2 RFP procurement.

The MRP Amendments

26. These concerns with the MRP Amendments were known by the IESO and were specifically raised in the covering memorandum before the IESO Board of Directors immediately prior to their approval:[8]

> Lastly, Technical Panel members and stakeholders continue to assert the importance of arriving at an acceptable resolution on gas generator contracts.

27. The IESO Board of Directors were aware of the NQS Generation Group's concerns and harms with the MRP Amendments raised in this Application but decided to approve the Amendments anyways.

28. Given the short legislative timelines and the lack of appropriate measures to mitigate the financial harm caused by MRP Amendments, the NQS Generation Group was left with no option other than to submit this Application under section 33(4) of the *Electricity Act, 1998* on the basis that the MRP Amendments are: (a) inconsistent with the purposes of the *Electricity Act, 1998*; and (b) unjustly discriminatory against a market participant or class of market participants.

C. GROUNDS FOR THE SECTION 33(4) REVIEW APPLICATION

29. At the heart of this Application is the concept that but-for the MRP Amendments, the harmful consequences would not flow to the NQS Generation Group. In other words, the cause of the harm set out in the Application is resulting from the MRP Amendments,

30. Over the past five (5) years, the IESO has refused to acknowledge and propose a resolution to concerns raised by the NQS Generation Group regarding unjust discrimination and inconsistency with the purposes of the *Electricity Act, 1998* resulting from the MRP Amendments. The IESO decided to publish the MRP Amendments in the face of those

[8] IESO, MRP, Materials provided to the IESO Board for discussion – Memorandum from Technical Panel Chair, 11 October 2024, online: <https://www.ieso.ca/-/media/Files/IESO/Document-Library/markets-committee/mc-20241017-Board-Memo-Final-Alignment.pdf>

concerns and despite acknowledging that the MRP Amendments will result in contractual implications for Deemed Dispatch Agreements held by the NQS Generation Group.[9]

31. The effect of implementing the MRP Amendments without <u>first</u> addressing the unjust treatment of the NQS Generation Group is to unjustly discriminate against a market participant or class of market participants, particularly:

    a. The harms to be suffered by members of the NQS Generation Group as a consequence of the MRP Amendments, including without limitation those harms summarized in paragraphs 9 and 23 above.

    b. Implementation of the MRP Amendments prior to resolving contractual amendments to the Deemed Dispatch Agreements results in an unequal bargaining position in favour of the IESO.

32. The MRP Amendments are also inconsistent with the purposes of the *Electricity Act, 1998*, including:

> (d) to promote the use of cleaner energy sources and technologies, including alternative energy sources and renewable energy sources, in a manner consistent with the policies of the Government of Ontario;
>
> (g) to promote economic efficiency and sustainability in the generation, transmission, distribution and sale of electricity; and
>
> (i) to facilitate the maintenance of a financially viable electricity industry.

33. The use of a deemed dispatch, or imputed net revenue, model in contractual arrangements following the implementation of the MRP Amendments is inconsistent with Subsections 1(d), (g) and (i) of the *Electricity Act, 1998* and fails to offset the discriminatory financial harm imposed by the MRP Amendments:

---

[9] IESO's Approach to Amending Market Participant Contracts in Response to the Market Renewal Program, online: <https://ieso.ca/-/media/Files/IESO/Document-Library/market-renewal/IESO-Approach-to-implement-MRP.ashx>

a. The NQS gas generation facilities operated by the NQS Generation Group are from clean energy sources and the Ontario Government states these facilities "play a key role in supporting grid reliability".[10] However, MRP will not promote the use of these facilities, rather MRP will result in these facilities being dispatched less often.

b. The NQS Generation Group construct and operate their generation facilities based on a reasonably predictable regulatory framework and financial return. Financially adverse MRP Amendments to the Market Rules midway through the term of a Deemed Dispatch Agreement (without any certainty of cost recovery resulting from those amendments) undermines market confidence in the economic efficiency and financial sustainability of electricity generation in Ontario.

D. CLOSING

34. For all of the foregoing reasons, the NQS Generation Group reiterates the request for relief set out in paragraph 2 of this Application.

35. Following disclosure by the IESO under section 6.3 of its Operator Licence EI-2013-0066 and the information requested in Schedule A, the NQS Generation Group proposes to file additional evidence as and when permitted by the OEB.

[10] Ontario, Powering Ontario's Growth – Ontario's Plan for a Clean Energy Future, July 2023, p.49.

6. MRP Implications for NQS Generators

52. Taken in their entirety, the MRP Amendments result in significant financial implications for the NQS Generators in multiple areas. When viewed collectively, the financial impact will be negative. Many of the financial implications described throughout this section are targeted specifically at NQS Generators and will not be applied to other MPs participating in the IAM. A detailed example of the implications is provided in the Appendix. The following table provides an overview of the financial impact discussed throughout this section.

Figure 4 Financial Impact of MRP Amendments for NQS Generators

	Current IAM Market Rules	MRP Amendments	Financial Impact on NQS Generators
Day-Ahead Commitment	NQS Generators submit three-part offers, the DACP optimizes commitments over a 24-hour period and provides physically binding schedules for NQS Generators only, which then are carried forward to RT.	NQS Generators submit three-part offers, which the DAM uses to optimize dispatch over a 24-hour period, resulting in financially binding schedules for all MPs.	Limited
Day-Ahead Settlement	There is currently no financial settlement in the DACP. For NQS Generators committed through the DA-PCG program, the costs submitted through three-part offers are calculated against that commitment in RT and RTM prices.	The DAM will result in two-settlement system for energy based on LMPs. The future DA-GOG program will incorporate changes to the schedule throughout the PD process when calculating the guarantee payment.	Moderate
Pre-Dispatch Commitment	The current PD calculation commits supply resources via the RT-GCG program based on incremental energy offers only. The RT-GCG program allows NQS Generators to voluntarily commit when incremental energy offers are economic for half of their MGBRT. PD optimization of schedules is limited to one hour at a time and energy and OR prices are uniform across the province	The MRP PD calculation will commit supply resources via the ERUC based on three-part offers. ERUC commitment is not voluntarily invoked. Optimization of ERUC commitments occurs over upwards of 27 contiguous hours, while energy and OR prices will be based LMPs.	Significant
Real-Time Dispatch	RT dispatch is based on the constrained mode while prices are based on the unconstrained mode.	The constrained and unconstrained mode will be retired and replaced with a SSM that will dispatch supply resources based on the cost of energy at each node in the IAM. Elimination of payments of CMSCs.	Moderate
Pre-Dispatch and Real Time Settlement	When voluntarily committing via the RT-GCG program, the associated RT-GCG payment is reduced by revenues earned up to MLP and through MGBRT only. Any OR revenues earned are excluded in the RT-GCG payment calculation.	When committed by ERUC, the associated RT-GOG payment will be reduced by all revenues earned on all supply, including OR.	Significant
Market Power Mitigation	Ex-post review of CMSC payments and submitted cost guarantee amounts.	Ex-ante review of all financial and operational parameters. Ex-post review of physical MWs offered.	Significant

53. The initial IESO Benefits Case for MRP recognized that it will result in negative financial outcomes for some supply resources compared to others. At the time of the Benefits Case, no detailed analysis had been undertaken to understand this outcome, nor is Power Advisory aware of any such analysis undertaken by the IESO since.

a. *"For any given market participant the impact of Market Renewal will not be just a proportional share of the societal efficiency gains, but a combined effect of efficiency gains, positive revenue impacts that favor more economically competitive resources, negative net revenue impacts that disfavor less valuable resources, and changes in wealth transfers. It is outside the scope of this study to estimate the net effects of these changes on individual classes of market participants, but we are able to comment on likely high-level impacts for customers and other market participants."*[12]

b. *However, some suppliers may be made worse-off as a result of certain reforms. Higher-cost and less-flexible off-contract generators may have a harder time competing in a more efficient market.*[13]

6.1 *Main MRP Design Changes and Amendments to the Market Rules Introduce Financial Risk to NQS Generators*

54. The MRP Amendments will – holding demand, energy offers, and other variables (e.g., transmission, etc.) constant – result in less commitment and dispatch of NQS Generators. Therefore, the MRP Amendments will result in less IAM revenues for the NQS Generators resulting from lower energy production and supply of energy and OR due to being committed and dispatched less. The impact will be experienced in all of the DAM, PD, and the RTM calculation engines and dispatch schedules compared to the current DACP, PD, and the RTM calculation engines. Overall, the combination of less commitment and dispatch will result in a negative financial outcome for NQS Generators. The Appendix provides both a daily and annual value of the potential financial impact.

55. *Reduced Commitment and Dispatch from MRP Market Design and Calculation Engines Due to Broader Cost Envelope*

a. One of the primary reasons for a reduction in commitment and dispatch of NQS Generators is that the IESO's calculation engines in the MRP Amendments will incorporate a broader suite of costs and operational constraints than is included in the existing calculation engines under the current IAM design and Market

[12] A Benefits Case Assessment of the Market Renewal Project, April 20, 2017, page 105, https://www.ieso.ca/-/media/Files/IESO/Document-Library/market-renewal/Benefits-Case-Assessment-Market-Renewal-Project-Clean-20170420.pdf

[13] A Benefits Case Assessment of the Market Renewal Project, April 20, 2017, page 111

Rules. This will limit the number of hours where NQS Generators will receive a DAM, PD, or RT schedule for energy production and/or OR supply.

b. As noted previously, NQS Generators will be required to submit three-part offers throughout the DAM and PD commitment processes. As such, when optimizing dispatch across the IAM, under the MRP Amendments the calculation engines will look beyond incremental energy offers – which is the only financial parameter used in the current PD and RTM calculation engines – when deciding to schedule an NQS Generator. The broader consideration of costs included within the MRP Amendments throughout the DAM to RTM calculation engines will limit commitment opportunities for NQS Generators, particularly when compared to other supply resources that will continue to largely participate on an incremental energy basis only

c. While the current DACP includes three-part offers for NQS generators, it is the PD commitment process – and the RT-GCG program that is based on the PD timeframe – that has historically accounted for a majority of commitments of NQS Generators. In the current IAM, the PD commitment provides a second opportunity – or hedge – for commitment if an NQS Generator is not successful in the DACP. Under the MRP Amendments, there will be a far more limited opportunity to receive a commitment following DAM, significantly reducing the second opportunity for NQS Generators to receive a commitment.

d. Consider the following example on the difference in commitment in the PD calculation engine based on the current IAM compared to the MRP Amendments. The values are based on a 600 MW NQS Generator with a 300 MW MLP and an incremental energy cost of $25/MWh, start-up costs of $20,000, and SNL costs of $5,000. If the NQS Generator is committed for its six-hour MGBRT to its MLP, its total commitment costs are $70,000 (($25/MWh * 300 * 6 Hours) + $20,000 start-up + $5,000 SNL)). In the current IAM, an NQS Generator's incremental costs for half of its MGBRT are the basis to invoke a commitment within three hours of RT. Under the MRP Amendments, incremental energy costs for the entire MGBRT, as well as start-up and SNL costs will be considered for a commitment. As shown in the table below, the economic "barrier" to commitment under the MRP Amendments is the significantly greater amount of costs that are included in the future calculation engine ($70,000 compared to $22,500), rendering the same NQS generator significantly less competitive under the MRP Amendments.

Figure 5 Costs Considered for Commitment

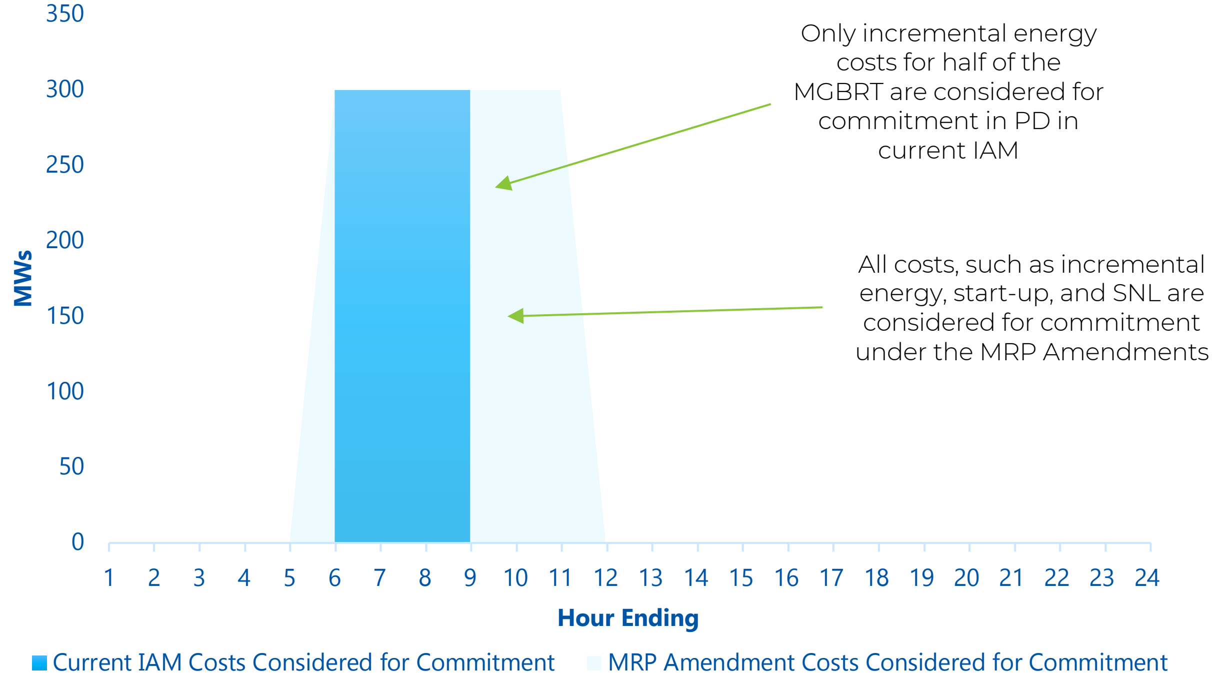


Figure 6 Costs Included in Calculation Engine for Commitment[14]

	Start-up Costs	SNL Costs	MGBRT Incremental Energy Costs	Total Costs Considered for Commitment
Current IAM	\$20,000	\$5,000	\$22,500	**\$22,500**
MRP Amendments	\$20,000	\$5,000	\$45,000	**\$70,000**

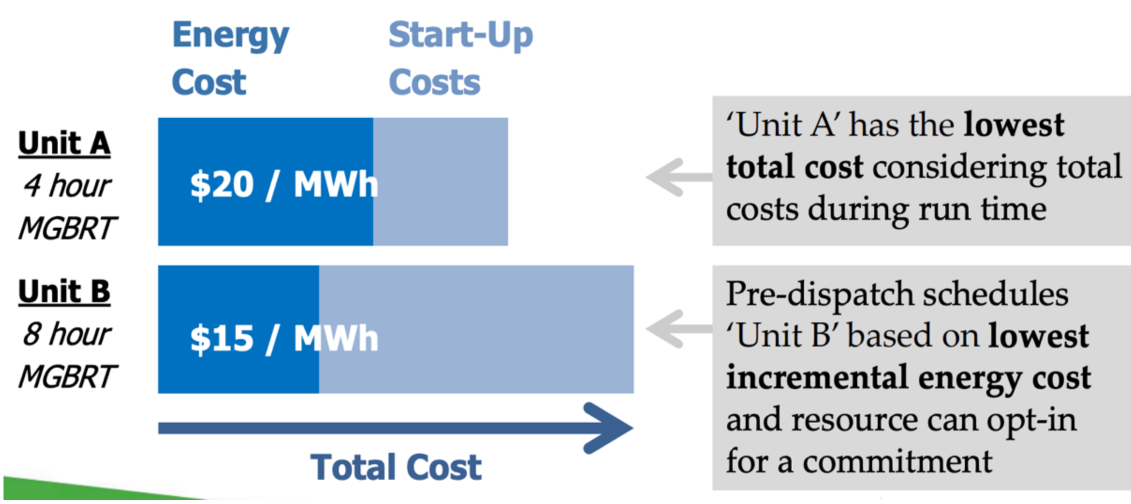
e. This highlights the different financial barriers to commitment for NQS Generators based on the current IAM compared to the MRP Amendments. In the current IAM, only the costs related to an NQS Generator's incremental energy offers for half of its MGBRT are used to invoke a commitment – if those offers are below the market clearing price, the NQS Generator can self-commit. Under the MRP Amendments, the broader suite of costs is significantly higher and reduces the opportunity for economic commitment. As shown in the table above, the economic "barrier" to commitment in the calculation engines under the MRP Amendments is \$70,000 compared to \$22,000 under the current IAM. As a result, the same NQS generator is rendered significantly less competitive due to the MRP Amendments, leading to negative financial outcomes relative to the current IAM.

f. The IESO's informational documents on MRP highlight that similar outcomes will occur in the future IAM compared to the current IAM due to the MRP

[14] For simplicity purposes, these values assume that SNL and incremental energy costs are separate in the current IAM when they are often combined.

Amendments.[15] In the IESO's example below, it compares two different NQS Generators with varying incremental energy and commitment costs. The IESO's example shows that in the current IAM, the lower incremental cost and longer MGBRT unit will be committed, but when all costs are included, an NQS Generator with lower incremental energy offers may not be the optimal outcome compared to an NQS Generator with higher incremental energy offers and lower total costs due to the shorter MGBRT. All else being equal, the unit with the higher incremental energy costs would never be committed over the one with lower incremental offers in the current PD process. When the total costs are included – as will occur under the MRP Amendments – the lower marginal cost unit with higher total costs and longer MGBRT will no longer be committed and dispatched. This is similar to the example above where both operational constraints and total costs are included in commitment and can result in dispatch that does not align solely with incremental energy offers and LMPs.

Figure 7 High Incremental Energy Offers Dispatched



56. *The Financial Implications of Changing Commitment Programs*

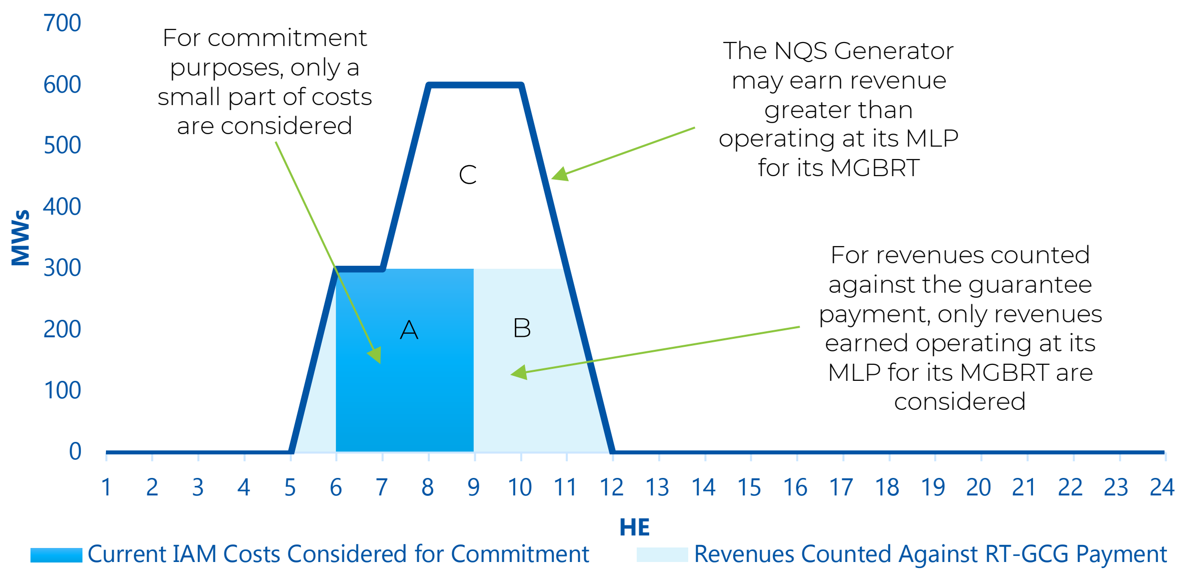
a. The MRP Amendments also include significant changes to the IESO's commitment programs for NQS Generators – particularly the elimination of the RT-GCG program and replacement with RT-GOG program that will produce negative financial outcomes for NQS Generators. At a high-level, the RT-GCG program allows NQS Generators to recover the cost of commitment when IAM energy revenues are insufficient.

b. Again, consider the 600 MW NQS Generator with a 300 MW MLP and an incremental energy cost of $25/MWh, start-up costs of $20,000, and SNL costs of

[15] See: https://www.ieso.ca/-/media/Files/IESO/Document-Library/public-info-session/2018/EA-non-quick-start-generators.pdf

$5,000. If the NQS Generator is committed for its six-hour MGBRT to its MLP, its total commitment costs are $70,000 (($25/MWh * 300 * 6 Hours) + $20,000 start-up + $5,000 SNL)). If the revenue earned by the NQS Generator from selling ***energy*** in the IAM is below that amount, it will receive a payment for the difference between its costs and revenues as part of the RT-GCG program, ensuring it recovers the full cost of commitment. Importantly, the current design of the RT-GCG program only incorporates revenues earned by the NQS Generator from selling ***energy*** up to its MLP, but no higher (300 MW in this example), and sold through its MGBRT, but no longer. The following figure provides an example of the IAM revenues counted against the RT-GCG payment and actual market revenues.

Figure 8 Current RT-GCG Calculation

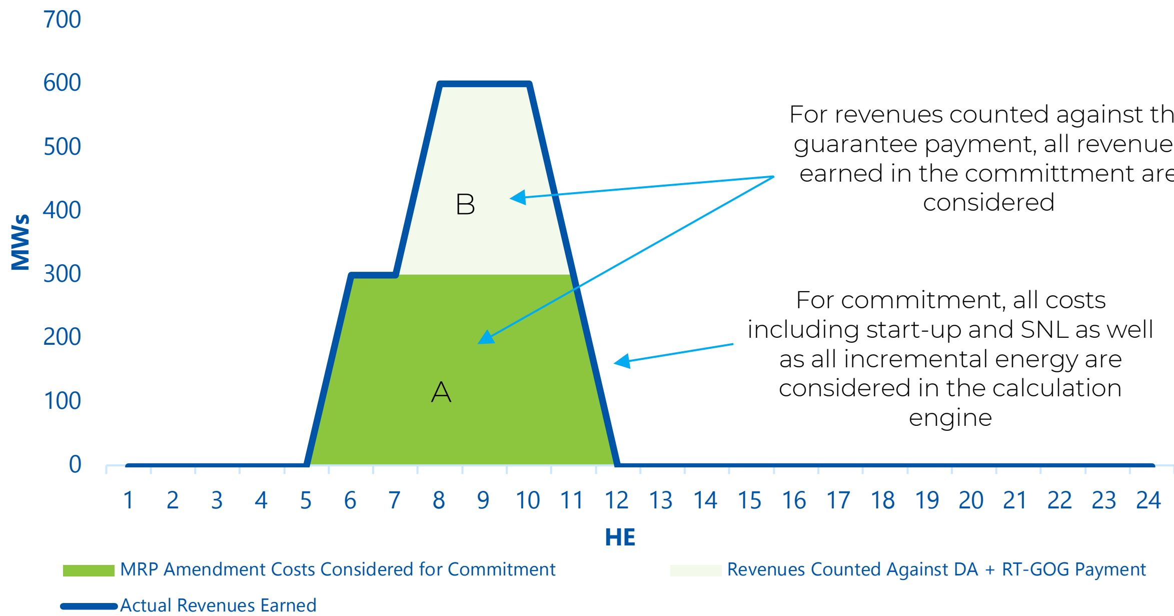


c. In the example above, only the costs in A are considered for commitment (i.e., incremental energy offers for half of its MGBRT). When calculating the RT-GCG payment – which is the difference in all of the costs to bring the generation unit online and revenues earned in the IAM – only the revenues earned in A and B are included. While the total IAM revenues of the NQS Generator are A, B, and C, that envelope is not included in the guarantee payment calculation.

d. In contrast, the DA-GOG and RT-GOG programs included in the MRP Amendments incorporate all IAM revenues earned through an NQS Generator's entire commitment. This is shown in the following example. The NQS Generator is scheduled up to its maximum output above its MLP for a few hours. The IAM revenues earned in these hours will be incorporated in the calculation of the guarantee payment (A and B in the following figure). This will reduce guarantee payments to NQS Generators (holding all variables constant) compared to the RT-GCG program to a commensurate degree. Overall, the financial outcome for

NQS Generators will be worse off regarding the RT-GOG program compared to the current RT-GCG program.

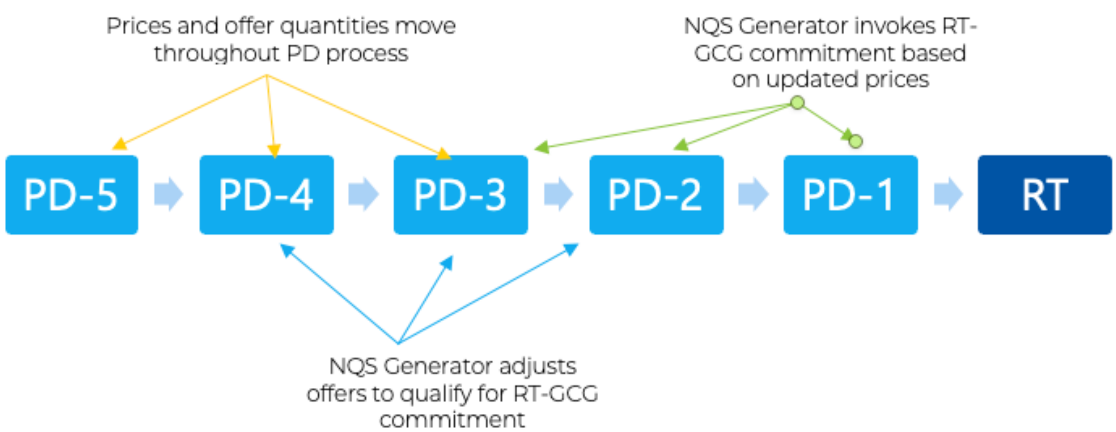
Figure 9 Guarantee Payments Under MRP Amendments



e. Additionally, the RT-GCG program does not include OR revenues earned by NQS Generators to offset guarantee payments. NQS Generators are often committed to provide OR to maintain the reliability of the grid. When NQS Generators are committed through the RT-GCG program, the spare energy available above their MLP – particularly in hours when wholesale energy prices are below their incremental energy costs – can be scheduled to provide OR. The RT-GOG program will incorporate OR revenues when calculating revenues that offset guarantee payments. This will reduce guarantee payments, holding all other variables constant, for NQS Generators and result in a negative financial outcome.

f. And finally, the current IAM design allows an NQS Generator to easily adjust energy offers to receive a commitment up until RT. The PD commitment process (via the RT-GCG program) provides multiple additional hedging opportunities for NQS Generators that were not successfully committed in the DACP. In the current PD process, NQS Generators compete on an incremental energy only basis to serve the significant portion of load not served by DACP commitments, which are limited to NQS Generators. During this period, NQS Generators receive ongoing market signals (i.e., wholesale prices) and have repeated opportunities to adjust offers to meet RT-GCG program commitment criteria (scheduled to MLP for half-MGBRT) and invoke a commitment. This provides them with repeated opportunities for commitment if they are not scheduled in the DACP and also allows them to compete against other supply resources on an incremental energy basis throughout the PD process. The following graph shows how an NQS Generator that has not been committed in the DACP can adjust its offers up until PD-2 (i.e., two hours prior to the respective dispatch hour in RTM) – in response to evolving market signals – to target a RT-GCG commitment. Throughout the PD-5, PD-4, and PD-3 timeframes, the NQS Generator can observe PD market prices and continually adjust offers in order to compete for a commitment. Once PD-2 begins offers can no longer be changed, but it can monitor prices in the PD-2 and PD-1 hours and at any time invoke a RT-GCG commitment provided it meets the criteria.

Figure 10 Commitment Opportunities Under Current IAM Design



g. In contrast, under the MRP Amendments, nearly all supply will be procured in the DAM with variations to schedules and prices occurring throughout the PD process due to forecast error. With most supply procured through the DAM, there will be a limited opportunity for an NQS Generator to target a commitment through the PD process by adjusting its offers, as most supply already has a financially-binding schedule. Additionally, the more comprehensive inputs in the PD commitment process under the MRP Amendments further limits the ability for an NQS Generator to target PD commitments as the cost envelope considered in the calculation engine is much larger. All told, under the MRP Amendments, an NQS Generator is less likely to receive a commitment in the DAM (all else being equal) and less likely to receive a commitment in the PD dispatch process, resulting in negative financial outcomes relative to the current IAM.

h. As shown in the following example, an NQS Generator (and all supply resources) will largely rely on the DAM to receive a commitment and financially-binding schedules. If unsuccessful, it then has a far more limited opportunity to target a PD commitment relative to the current IAM. Less commitment through the PD process under the MRP Amendments will reduce revenues and guarantee payments compared to the current IAM, resulting in a negative financial outcome.

Figure 11 Commitment Opportunity under MRP Amendments

i. The Appendix provides a detailed example of settlement in the current IAM and under the MRP Amendments.

57. *The Financial Risk of Reduced Commitment Due to Operational Constraints*

a. The inclusion of operational parameters – such as MGBRT and MLP – in the calculation engines of DAM and ERUC dispatch and scheduling algorithms will result in commitment and dispatch that varies from commitment and dispatch in the current IAM. Essentially, the operational constraints of different supply resources can result in dispatch that does not align with the economic merit order of the supply resources.

b. The following example provides a simplified outcome of how an NQS Generator may not be committed even though it would be "in merit" or financially viable based on its three-part offers and market prices. The simplified example includes three NQS Generators with different MLPs, incremental energy costs, and start-up costs. The total system demand is 475 MW and the three supply resources will be dispatched in order to minimize total costs.[16]

[16] This is a simplified example that assumes SNL costs are incorporated in incremental energy offers. It also assumes that there is no congestion or line losses, so LMPs are the same across resources.

Table 1 Proxy NQS Units for Dispatch Example[17]

System Demand = 475 MW				
Unit	Marginal Cost of Unit	Minimum Loading Point	Max Capacity of Unit	Start-up Costs
A	$20	300	350	$1,000
B	$30	200	300	$500
C	$40	100	400	$100

c. Any commitment of the generation units will have to respect operational parameters (MLP in this example). For example, if units A and B are committed, the combined MLP (500 MW) is not operationally feasible, as that minimum generation quantity is greater than the total demand (475 MW) – neither one of the supply resources can be dispatched below their MLP to resolve the oversupply. Conversely, if the combined Max Capacity of the committed resources is less than the total demand, demand cannot be served and there is an undersupply of energy. As shown in the following table, only two configurations are possible given these constraints: committing Unit A and Unit C together or committing Unit B and Unit C together. All other scenarios either result in infeasible oversupply or undersupply situations.

d. Given the two configuration options, the DAM and/or ERUC commitment and dispatch algorithms would choose to commit units A and C, as their combined Total Cost is lower than committing units B and C.

e. In both cases (configurations AC and BC), the LMP is set by Unit C at $40/MWh, as it serves the last MWh of demand.

f. Importantly, with an LMP of $40/MWh, Unit B – which did not receive a commitment – is economic, but not dispatched. With a marginal cost and incremental energy offer of $30/MWh, Unit B is priced below the LMP of $40/MWh and could make a notional profit of $10/MWh on every MWh it supplies. With a Max Capacity of 300 MW, Unit B could have made a notional profit of $3,000 ($10/MWh * 300 MW) on its generation if it were dispatched – with this profit far exceeding its $500 start-up cost, making Unit B economic on an all-in cost basis and earning a notional profit of $2,500 ($3,000 generation profit - $500 start-up cost). Despite being economic, Unit B is not committed due to the interplay of physical constraints considered within the DAM and ERUC commitment and dispatch algorithms (in this case, the interaction of its MLP with the MLPs of other units). Commitment decisions in the current IAM do not factor in many of the physical constraints that will be considered under the MRP Amendments. To the extent any are, they are communicated in PD prices that

[17] Note that this example is largely borrowed from a presentation by ISO-NE, which has three-part offers. See: https://www.iso-ne.com/static-assets/documents/100012/20240605-03-newem-unit-commitment-dispatch-print.pdf

are shared with NQS Generators in advance of voluntary commitment decisions through the RT-GCG, giving them the opportunity to adjust offers and operating strategies around these constraints. As a result of the changes associated with the MRP Amendments, this will result in negative financial outcomes relative to the current IAM.

Table 2 Dispatch and System Costs with Constraints

Configurations	Units	Combined MLP (MW)	Max Capacity (MW)	Total Cost of MLP ($)	Feasible	Incremental Costs	Total Cost	LMP
1	ABC	600	1050	$17,600	N	N	N	$40
2	AB	500	650	$13,500	N	N	N	$30
3	AC	400	750	$11,100	Y	$2,000	$13,100	$40
4	BC	300	700	$10,600	Y	$6,000	$16,600	$40
5	A	300	350	$7,000	N	N	N	$20
6	B	200	300	$6,500	N	N	N	$30
7	C	100	400	$4,100	N	N	N	$40

g. While this example is simplified, it highlights that full optimization of commitment and dispatch across operational and financial parameters under the MRP Amendments can differ significantly from that based only on incremental energy offers, as is the case in PD under the IAM. This example highlights potential lost revenue opportunities for NQS Generators under the MRP Amendments compared to the current IAM. As noted elsewhere, the divergence between this outcome and the "deeming" settlement mechanism within the contracts held between NQS Generators and the IESO exacerbates the financial harm.

58. *MPM in the MRP Amendments*

a. The MRP Amendments are implementing an extensive MPM framework that currently does not exist and will negatively impact NQS Generators. NQS Generators will be disproportionately impacted by the MPM framework given they are likely to experience mitigation back to reference levels that do not result in infra-marginal rents in the IAM.

b. The current MPM framework is done on a protracted *ex-post* basis and is administratively burdensome, contributing to a relatively low volume of cases. With the two-schedule system and uniform prices based on the market schedule, market power is largely addressed through *ex-post* reviews and clawbacks of payments of CMSCs and other payments. Because market power is addressed through a clawback of these payments, it does not have an impact on other supply resources across the IAM, as it focuses only on payments made to each individual supply resource. The current DACP – that is not financially-binding and only provides advisory schedules apart from DA-PCG schedules – does not incorporate a MPM framework at all.

c. The future MPM framework under MRP – as discussed previously – will apply extensive screens of energy and operational parameters on an *ex-ante* basis in all of the DAM, PD, and RTM calculation engines. If the resource is determined to have market power and, based on the IESO's assessment, these parameters fall outside IESO-determined ranges (for instance, incremental energy offer exceeds marginal operating cost, or MLP exceeds IESO-determined MLP of the unit), the IESO will replace the MPs submitted parameter with the IESO-determined mitigated parameter. This replacement occurs in conjunction with market scheduling, and prior to operation and settlement, such that the impacts of the mitigation are incorporated into those processes. This *ex-ante* mitigation is carried out automatically by the IESO's tools. As noted above, MPM under the current IAM is neither ex-ante, nor automatically carried out.

d. For example, consider an NQS Generator with a reference level energy cost of \$30/MWh (i.e. IESO-determined replacement offer price), where the applicable energy LMP within the respective constrained zone is set by the NQS Generator through a \$100/MWh energy offer. This NQS Generator will then find itself subject to the IESO's MPM Conduct and Impact Test – which, at its most basic level, reviews whether the "conduct" of the offer was a certain amount greater than the reference level, and its "impact" on the LMP was greater than a than a pre-determined amount (as detailed in the MRP Amendments). If this NQS Generator fails that Test, its energy offer will be replaced with the pre-determined reference level of \$30/MWh.

e. In addition to MPM screens on incremental energy offers, the IESO will also screen and replace start-up and SNL costs, as well operational parameters such as MGBRT, MLPs and ramp rates. The number of NQS Generators parameters that are subject to MPM is far greater than other classes of the supply resources in the IAM (discussed elsewhere). Therefore, under MPM within MRP, there are many more ways for NQS Generators to be captured in the MPM framework than competing resources.

f. As noted, NQS Generators are often wholesale market price-setting supply resources when committed in the IAM due to the province's extensive amount of baseload, low marginal cost supply (see following figure).[18] The potential for NQS Generators to have their energy, OR, and other components of their offers

[18] See the most up-to-date information from the MSP: https://www.oeb.ca/sites/default/files/msp-monitoring-report-202303.pdf

subject to MPM is far greater than other supply resources. The risk of mitigation – along with the other financial risks described throughout this report, such as reduction in guarantee payments – imposes significantly greater financial risks to NQS Generators compared to other supply resources.

Figure 12 NQS Generators Set Price More Than Any Other Resource Type

Table A-1: Share of Hours of Resource Type Setting the Pre-Dispatch and Real-Time MCP, 3 Periods

Resource	Summer 2020		Winter 2020/21		Summer 2021	
	PD-1	RT	PD-1	RT	PD-1	RT
Hydro	23%	39%	19%	49%	17%	43%
Wind	11%	21%	9%	20%	5%	11%
Gas	36%	53%	32%	42%	41%	62%
Nuclear	0%	1%	0%	0%	0%	0%
Solar	1%	0%	1%	0%	0%	0%
Biofuel	1%	2%	1%	2%	0%	0%
Imports	13%	-	30%	-	27%	-
Exports	31%	-	23%	-	23%	-
Loads	1%	-	2%	-	1%	-

59. The MRP Amendments also include an *ex-post* review of physical MWs submitted by supply resources. If, for example, a supply resource was found to have withheld MWs in order to exercise market power – or at least is found to have done so by the IESO – the calculation engines will be run with the new reference MW amounts and settlement amounts will be adjusted accordingly. No such ex-post adjustment process exists for similar circumstances in the current IAM.

60. And finally, under the IESO's MRP Amendments, the IESO will apply its new restrictive MPM framework to the OR market as well, which currently has little market power mitigation in today's IAM (which is limited to screening for CMSCs only). As part of the MRP Amendments, the IESO will screen and potentially replace OR offers when they are greater than $15/MW and it considers there to be "global" market power across the entire IAM. This creates a de facto $15/MW price cap on OR during certain circumstances, whereas OR prices in the current IAM face no such cap and often exceed this threshold – with more than 12% of all hours in 2023 greater than $15/MW. This poses an additional risk for NQS Generators as large providers of OR, whereas nuclear, wind and solar generators are not impacted as they do not provide OR.[19]

[19] OR providers must be able to sustain output for one hour. Nuclear resources are typically placed at the bottom of the energy supply stack. The MSP has historically reviewed the providers of OR and it is dominated by hydro, gas and dispatchable loads. See: https://www.oeb.ca/sites/default/files/msp-monitoring-report-202303.pdf

6.2 *Commentary on MRP Design Changes and Amendments to the Market Rules Impacts on other non-NQS Generators*

61. NQS Generators are being treated differently under the MRP Amendments than other supply resources (e.g., nuclear, hydroelectric, wind and solar generation, energy storage, imports, and dispatchable loads). Due to the difference in treatment, NQS Generators face a greater negative financial impact than other resource types as a result of the MRP Amendments.

62. NQS Generators are the only supply resources facing material changes in the financial settlement and dispatch related to commitment programs, such as the elimination of the RT-GCG program and its replacement with commitment processes that result in relatively negative financial outcomes under MRP. No other supply resource faces the challenge of having to compete on costs beyond incremental energy costs – including start-up and SNL costs – and the impact this may have on commitment, dispatch and settlement under the MRP Amendments. None of wind, solar, hydroelectric and nuclear generators rely on cost guarantee programs such as the RT-GCG in the current IAM to maintain financial viability of dispatch. As such, no other supply resource will face the negative financial impact of changes to these guarantee programs due to the MRP Amendments.

63. The risk of lower commitment and dispatch and a greater reliance on a financially binding DAM, maximum and contiguous 27 hour-LAP in the PD calculation engine and optimization of all costs in the DAM, PD and RT calculation engines are risks faced primarily – and in some cases exclusively – by NQS Generators, while having little impact on other supply resources in the IAM. The ability in the current IAM for NQS Generators to voluntarily invoke the RT-GCG program, for example, provides NQS Generators with flexibility in managing commitment and dispatch throughout the PD process, where most resources are currently committed.

64. Other supply resources such as qualified hydroelectric generators – contrary to facing the risk of reduced commitment and dispatch as a result of the MRP Amendments – will have a variety of parameters included in the calculation engines that will provide greater control over their commitment. As part of the MRP Amendments, these hydroelectric generators will be able to specify a number of operational parameters – such as maximum starts and must-run daily energy amounts, among multiple other parameters – that will limit the calculation engine's ability to commit and dispatch these resources in a manner that differs from the preferences of the resource's operators. The following table highlights the various physical dispatch parameters that will be included in the calculation engine. Note that both NQS Generators and hydroelectric resources will have a number of new parameters as a result of the MRP Amendments.

65. The differences between how these parameters are treated for NQS Generators and hydroelectric resources in terms of MPM and administratively set offers is material. Every single parameter (apart from daily energy limit) for NQS Generators is subject to mitigation. This means that the IESO can change these parameters if NQS Generators

offer them differently than IESO-determined levels. This can severely limit the ability of NQS Generators to dictate to the calculation engines how they should be committed and dispatched. Conversely, for hydroelectric generators, only ramp rates and maximum starts per day are subject to mitigation. This means that these supply resources can dictate the minimum amount of energy – among other parameters – that the IESO calculation engine must consider without facing the threat of mitigation and administratively set levels. This is a significant difference between how the NQS Generators are treated under the MRP Amendments, offering hydroelectric generators far more flexibility to manage operational and financial risk relative to NQS Generators. This outcome is a direct result of the MRP Amendments and will contribute to negative financial outcomes for NQS Generators relative to hydroelectric generators.

Figure 13 Dispatch Parameters in the MRP Amendments

Dispatch Data Type	Dispatch Data Parameter	Existing or New	Generation Facility Type					
			Dispatchable					Non-Dispatchable (Self-scheduling, Transitional, Intermittent)
			NQS (Nuclear)	NQS (Other)	Quick Start (Variable Generator)	Quick Start (Hydro-electric)	Quick Start (Other)	
Id	Registered market participant name	Existing	x	x	x	x	x	x
Id	Resource type	Existing	x	x	x	x	x	x
Id	Resource name	Existing	x	x	x	x	x	x
Hourly	Energy *offer*	Existing	x	x	x	x	x	x
Hourly	Start-up *offer*	New		x				
Hourly	Speed no-load *offer*	New		x				
Hourly	*Energy* ramp rate	Existing	x	x	x	x	x	
Hourly	Minimum hourly output	New				x		
Hourly	Hourly must-run	New				x		
Hourly	*Variable generation* forecast quantity	New			x			
Daily	Linked resources, time lag and MWh ratio	New				x		
Daily	*Forbidden regions*	New				x		
Daily	Maximum daily *energy* limit	Existing		x	x	x	x	
Daily	Minimum daily *energy* limit	New				x		
Daily	Minimum loading point	Existing		x				
Daily	Minimum generation block run-time	Existing		x				
Daily	Minimum generation block down time	Existing		x				
Daily	Maximum number of starts per day	Existing		x		x		
Daily	Single cycle mode	Existing		x				
Daily	Lead time	New		x				
Daily	Ramp up *energy* to MLP (Ramp hours to MLP and *Energy* per ramp hour)	New		x				

More than 12 parameters for NQS Generators subject to mitigation compared to 2 for hydroelectric

66. Wind and solar generators, meanwhile, can opt to have their forecasted energy production provided by the IESO and divergences between DAM and RTM – which would introduce financial risk that is not present in the current IAM – fully offset through IESO proposed contract amendments. While not a major component of this evidence, these proposed contract amendments for wind and solar generators to eliminate the financial risk of a financially binding DAM should be considered in the context of the financial harm facing NQS Generators that lack a commensurate off-setting mechanism in their contract amendments proposed by the IESO.

67. Wind and solar generators faced the risk that their capability to produce energy based on fuel availability will be different between the DA and RT timeframes ("DART risk") (e.g., the wind speeds decline or the sky becomes overcast relative to forecasts DA). This would have meant that their DAM revenues would be diminished if they could not deliver on their DAM schedules in the RTM. ***Notably, the IESO has offered contract amendments to the wind and solar generators to eliminate this risk to which they are exposed.***

68. As noted, MPM under MRP will apply to a significantly greater number of operational parameters for NQS Generators than other supply resources. Nearly every element of operation of an NQS Generator – including the number of hours it takes to start, MGBRT, MLP and various financial costs – will be screened by the IESO for market power. Other supply resources (e.g., nuclear, hydroelectric, wind and solar generation, energy storage, imports, and dispatchable loads) – that compete on an incremental energy basis will face a much less exhaustive MPM framework under MRP. Not only will these parameters and associated costs limit the commitment and dispatch of NQS Generators, it will also limit their ability to control these parameters due to the implementation of IESO-determined reference levels on nearly every aspect of their financial offers and physical operations. Importantly, many of the dispatch parameters available to other resource types are not subject to mitigation as they are for NQS Generators.

APPENDIX A: LIST OF NQS GENERATORS[37]

Contract Type	Contract Capacity (MW)	Facility Name	Supplier Legal Name
CHP I	84	East Windsor CoGen	East Windsor Cogeneration LP
ACES	839.1	Goreway Station	Goreway Station Partnership
ACES	550	Portlands Energy Centre	Portlands Energy Centre L.P.
CES	641.5	Halton Hills Generating Station	Portlands Energy Centre L.P.
CES	900	Napanee Generating Station	Portlands Energy Centre L.P.
CES	577	St. Clair Energy Centre	St. Clair Power LP
CHP I	241.6	Thorold Cogeneration Project	Thorold CoGen L.P.
EMCES	444	Sarnia Cogeneration Plant	TransAlta Generation Partnership, an Alberta General Partnership of TransAlta Generation Ltd. And TransAlta Corporation
NYRP	393	York Energy Centre	York Energy Centre LP

[37] Note that York Energy Centre and East Windsor do not participate as an NQS Generator in the RT-GCG program.

APPENDIX B: DETAILED DAILY SETTLEMENT EXAMPLE

The following section is intended to provide a detailed example of daily settlement for a proxy NQS Generator, including the potential financial impact from the design of the current contracts held by NQS Generators. The proxy generator is based on a representative asset of facilities owned and operated by the NQS Generation Group. While the IAM prices and natural gas values are based on actual values (September 12, 2019), this example is intended to provide a detailed – but theoretical – analysis for the potential IESO commitment and dispatch in the current IAM and commitment and dispatch under the MRP Amendments for a typical NQS Generator.

The basic parameters for the proxy NQS Generator are shown in the following table.

Figure 18 Proxy NQS Generator Parameters

Installed Capacity (MW)	Heat Rate (MMBtu/MWh)	Start-up Costs (MMBTu/Start-up)	O&M Costs ($/MWh)	MLP (MW)	MBGRT (Hours)
600	7.5	$6,000	$0.50	300	6

The following tables provides the commitment and dispatch of the proxy generator. Each of the important outputs are discussed on the following page.

Figure 19 Daily Settlement for Proxy Generator

HE	PD-3 Price ($/MWh)	HOEP ($/MWh)	OR Price (30R) ($/MW)	Incremental Energy Offer ($/MWh)	RT-GCG Commitment (MWh)	CMSC Revenue ($)	Potential OR Revenue ($)	Start-up Costs ($)	Energy Market Profit ($)	Deemed Output (MWh)
1	$13.01	$9.69	$0.20	$24.08		$0	$0	$18,860	$0	
2	$5.56	$11.41	$0.20	$24.08		$0	$0	$18,860	$0	
3	$13.00	$2.76	$0.20	$24.08		$0	$0	$18,860	$0	
4	$3.00	$0.00	$0.20	$24.08		$0	$0	$18,860	$0	
5	$14.35	($1.50)	$0.20	$24.08	300	$7,673	$60	$18,860	($7,673)	
6	$26.39	$11.70	$0.27	$24.08	300	$3,713	$81	$18,860	($3,713)	
7	$27.45	$25.50	$0.22	$24.08	300	$0	$66	$18,860	$427	600
8	$23.89	$23.11	$0.23	$24.08	300	$290	$69	$18,860	($290)	600
9	$23.36	$14.38	$0.23	$24.08	300	$2,909	$69	$18,860	($2,909)	600
10	$25.89	$1.42	$0.24	$24.08	300	$6,797	$72	$18,860	($6,797)	
11	$20.00	$4.73	$0.27	$24.08		$0	$0	$18,860	$0	
12	$13.03	$13.45	$0.27	$24.08		$0	$0	$18,860	$0	
13	$13.02	$21.71	$0.24	$24.08		$0	$0	$18,860	$0	
14	$13.37	$24.21	$0.25	$24.08		$0	$0	$18,860	$0	
15	$14.00	$27.48	$0.33	$24.08	300	$0	$99	$18,860	$1,021	
16	$20.21	$19.61	$0.54	$24.08	300	$1,340	$162	$18,860	($1,340)	
17	$20.21	$26.05	$0.56	$24.08	300	$0	$168	$18,860	$592	
18	$25.88	$22.56	$0.89	$24.08	300	$455	$267	$18,860	($455)	600
19	$30.13	$21.35	$7.82	$24.08	300	$818	$2,346	$18,860	($818)	600
20	$26.91	$18.22	$5.90	$24.08	300	$1,757	$1,770	$18,860	($1,757)	
21	$13.33	$13.12	$2.04	$24.08		$0	$0	$18,860	$0	
22	$5.72	$6.36	$0.45	$24.08		$0	$0	$18,860	$0	
23	$0.00	$0.49	$0.28	$24.08		$0	$0	$18,860	$0	
24	$0.00	($0.04)	$0.20	$24.08		$0	$0	$18,860	$0	

1. *Commitment and Dispatch under current Market Rules*

   a. *Commitment in the DACP* – Commitment is unlikely if historical PD-3 prices are considered a proxy for DACP prices (note that the IESO does not provide historical DACP shadow prices beyond one month on its website). It is likely that DA prices on this day would be similar to the PD prices in this table. As shown in the Economic Operating Profit values in the figure above, the total costs of starting the NQS Generator and providing energy up to its MLP over its six-hour MGBRT are significantly greater than revenues earned in the IAM. As such, it is unlikely that the NQS Generator would receive a DA-PCG commitment on this day.

   b. *Commitment in PD Under Current Market Rules* – Based on the current IAM design, the proxy NQS Generator could invoke a RT-GCG commitment in two different instances on this day. The first instance is from HE 5 – 10 where its incremental energy offers are economic (i.e., in merit) for 3 of the 6 hours of its MGBRT. In these hours, the NQS Generator would be "constrained on" by the IESO to its MLP for its 6-hour MGBRT. Additionally, the NQS Generator could invoke a RT-GCG commitment in HE 15 – 20 for the same reasons as the previous commitment – its incremental energy offers are economic for at least half of its 6-hour MGBRT.

   c. *Commitment and Dispatch in RT Under Current Market Rules* – In RT the NQS Generator would be constrained on to its MLP for its MGBRT in both commitments. In hours where the NQS Generator's incremental energy offers are uneconomic, it would be paid a CMSC to ensure that it follows dispatch up to its MLP. Additionally, the NQS Generator can potentially provide OR with the 300 MW of spare capacity for all of the hours it is constrained on as part of the RT-GCG commitment.

   d. *Settlement Under Current Market Rules* – The NQS Generator will not fully recover its incremental energy and start-up costs through IAM energy market revenues earned up to its MLP throughout its MGBRT. For example, the cost of a start-up is $18,860 for each start. In the first RT-GCG commitment, including payment of CMSCs for incremental energy up to its MLP, the NQS Generator only earns $427 in Operating Profit that can be counted against the $18,860 in total start-up costs (the payment of CMSCs fully offset incremental energy costs in hours where it is not economic). As such, the NQS Generator will be provided a guarantee payment from the RT-GCG program of $18,433. A similar calculation is done with the second start, resulting in a guarantee payment of $17,247. Additionally, the NQS Generator can potentially earn $5,229 in OR revenues that are not included in the RT-GCG calculation amounts.

   e. *Market Power Mitigation Under Current Market Rules* – None of the NQS Generator's incremental energy, OR offers, or physical parameters are screened for MPM on an ex-ante basis. Note that RT-GCG costs are now pre-approved with the IESO.

2. *Commitment and Dispatch under MRP Amendments*

a. *Commitment in the DAM* – Based on 24-optimization and three-part offers, the NQS Generator is likely not committed in the DAM, as the IAM energy market and OR revenues are significantly below its as offered costs.

b. *Commitment in PD Under MRP Amendments* – Similar to the DAM outcome, the 27-hour LAP and its multi-hour optimization will likely severely limit the commitment of the proxy NQS Generator. Similarly to the DAM, the as offered costs are significantly greater than potential IAM energy and OR revenues and the unit is largely uneconomic throughout the day.

c. *Commitment and Dispatch in RT Under MRP Amendments* – Given the lack of DAM and PD commitment, the NQS Generator is not dispatched in RT.

d. *Settlement Under MRP Amendments* – There is no settlement to account for. If, for example, the NQS Generator was committed for the second start of the day, its guarantee payment would be reduced by $4,908, as this is the amount of IAM revenue that the NQS Generator would earn through OR as part of its second commitment (in addition to energy revenues beyond its MLP). These revenues would be deducted from the guarantee payment – unlike the current IAM where these revenues are not included in the revenue calculation.

e. *Market Power Mitigation Under MRP Amendments* – Every single component of financial (energy, OR, start-up and SNL costs) would be screened on an *ex-ante* basis for MPM. Operational parameters – such as MGBRT, MLP, and other parameters – would also be screened on an *ex-ante* basis. If, for example, the NQS Generator increased its MGBRT or MLP amounts, the IESO could potentially replace those with pre-determined Reference Levels that may result in commitment and dispatch. The amount of MWs offered by the NQS Generator will also be screened on an *ex- post* basis to determine whether the NQS Generator did not offer its full supply.

3. *Deemed Supply Under Existing Contracts*

   a. The NQS Generator would be "deemed" to have operated in five hours. All of these five hours occur at the same time as the RT-GCG commitments. The IAM revenues are "deemed" to have been earned in these five hours are counted against the monthly net revenue amounts that are included in the monthly capacity payment made to the NQS Generator. The RT-GCG commitment provides a hedge against contract "deemed" dispatch that is not available under the MRP Amendments.

4. *Total Financial Impact from MRP Amendments*

   a. The total financial impact to the NQS Generator amounts to:

      i. Two less commitments in the PD calculation engine.

      ii. The loss of potential OR revenues for OR amounts in the two commitments invoked under the RT-GCG program.

      iii. If commitment were to occur under the MRP Amendments, the DA-GOG or RT-GOG would include OR revenues and reduce the guarantee payment to a commensurate degree.

      iv. An *ex-ante* and *ex-post* review of every single financial and operational parameter for the NQS Generator and potential for replacement to reference levels.

      v. A misalignment between the "deeming" mechanism included in the contracts with the IESO and actual commitment and dispatch in the IAM.

The total financial impact to the NQS Generator on this day is more than $40,000 in revenues that it could earn in the current IAM compared to the likely outcome of earning $0 under the MRP Amendments.

Figure 20 Daily Financial Impact of MRP Amendments

RT-GCG Payment #1	RT-GCG Payment #2	OR Revenue	Total Revenue in Current IAM that No Earned Under MRP Amendments
$18,433	$17,247	$5,229	$40,909

APPENDIX C: HISTORICAL ANNUAL FINANCIAL IMPACT OF MRP AMENDMENTS

The following section is intended to provide an estimate on the financial impact of changes of the MRP Amendments on a proxy NQS Generator on an annual basis. The parameters of the NQS Generator are the same as described in Appendix B.

Figure 21 Proxy NQS Generator Parameters

Installed Capacity (MW)	Heat Rate (MMBtu/MWh)	Start-up Costs (MMBTu/Start-up)	O&M Costs ($/MWh)	MLP (MW)	MBGRT (Hours)
600	7.5	$6,000	$0.50	300	6

Using historical pricing data from 2018 to 2023, a financial impact analysis was conducted for the proxy generator. The analysis considered the financial and physical parameters described above and compared the annual net margin when operating in the IAM for the proxy generator operating under the current Market Rules compared to the MRP Amendments.

Figure 22 Annual Financial Impact

	Current Market Rules			MRP Amendments			Total Impact of MRP Amendments
	Total Costs	Total Revenues	Net Margin	Total Costs	Total Revenues	Net Margin	
2018	$80,973,054	$93,968,212	$12,995,158	$70,034,767	$80,264,878	$10,230,111	$2,765,047
2019	$48,785,136	$57,600,949	$8,815,813	$39,824,159	$46,071,132	$6,246,973	$2,568,840
2020	$32,164,975	$39,715,240	$7,550,265	$25,417,417	$29,514,617	$4,097,201	$3,453,064
2021	$66,567,075	$77,565,626	$10,998,550	$50,676,340	$57,754,731	$7,078,391	$3,920,159
2022	$156,685,435	$176,969,063	$20,283,629	$139,760,846	$155,402,546	$15,641,700	$4,641,929
2023	$107,809,735	$143,733,555	$35,923,820	$103,999,098	$136,258,298	$32,259,199	$3,664,621
Total	**$492,985,410**	**$589,552,645**	**$96,567,236**	**$429,712,626**	**$505,266,202**	**$75,553,576**	**$21,013,660**

AS noted throughout the evidence, the NQS Generators will be committed and dispatched less within the IAM under the MRP Amendments. This will result in less wholesale market revenues and profit compared to the current Market Rules. The financial impact from this outcome is significant. In order to isolate this impact, total costs are compared to total revenues based on differences in dispatch and commitment. The total costs included in the analysis incorporates all costs related to providing energy (such as incremental energy costs and SNL), as well as the costs related to starting the NQS for each commitment and dispatch run. The total revenues incorporate all of the revenues earned by the NQS generator, including:

- Revenues earned from selling energy;
- Guarantee payments;
- Associated CMSC payments (under the current Market Rules);
- OR revenues.

Ultimately, the analysis incorporates a financial dispatch of the proxy NQS Generator under the different Market Rules (current versus the MRP Amendments) and the associated revenues and costs with that dispatch. Notably, the analysis is an economic modelling of the NQS Generator and does not capture the physical constraints and resulting reduction in commitment that may occur under the MRP Amendments (as described previously in this report in paragraph 56). It also does not capture the financial impact of MPM resulting from the MRP Amendments, which is expected to reduce the potential economic rents earned through higher wholesale pricing, among other factors. As noted throughout this report, both of those factors are expected to result in additional financial impacts to NQS Generators as a result of the MRP Amendments – and more so than other resource types.

Figure 23 Contract Financial Impact

	Number of Run-Time Hours under current Market Rules	Number of Run-Time Hours under MRP Amendments	Contract Financial Impact
2018	4,826	3,524	$5,695,878
2019	3,604	2,360	$5,241,366
2020	3,267	2,084	$4,523,886
2021	3,422	2,041	$10,741,404
2022	5,070	3,834	$8,788,656
2023	7,660	6,785	$3,422,274
Total	27,849	20,628	$38,413,464

To calculate the contract financial impact Power Advisory compared the number of hours where the NQS Generator is deemed to have been online using the current deemed dispatch contract compared to the number of hours where the NQS Generator is committed in the physical market under the current Market Rules and the MRP Amendments. As demonstrated in Appendix B, the RT-GCG is commonly utilized by NQS Generators as a means of hedging against the risk of being "deemed" to have operated, but not physically committed and dispatched in the IAM. As result, instances of being deemed to have operated but not being physically committed and dispatched in the IAM are rare under the current Market Rules. Due to the MRP Amendments, the risk of being deemed to have operated but not committed in the IAM will increase. In such hours, the deemed revenues – and associated contract payment reductions – are not being offset by IAM revenues. As shown in the table above, the number of hours of commitment is lower in every year under the MRP Amendments compared to the current Market Rules, but the number of deemed hours for the proxy NQS Generator remains the same. The net result is that the number of hours where the disconnect between being deemed and physically operating in the IAM has increased by 7,221 hours, resulting in a $38, 413,464 financial impact to the proxy NQS Generator over the 2018 – 2023 time frame.

ONTARIO ENERGY BOARD

Market Surveillance Panel

State of the Market Report 2023

September 2024

Ontario Energy Board

10 FUTURE OF ONTARIO MARKET DESIGN

Markets can drive efficiency by creating incentives which align with the market's needs and encourage efficient behavior. Where market design does not align incentives with market needs, inefficient behavior may be induced. In the *State of the Market Report 2022*, the Panel discussed several design elements of the Ontario market which do not promote efficiency. To help address a number of these design inefficiencies, the IESO is presently in the process of completing work on its Market Renewal Program (MRP), with a view to deployment in mid-2025.

10.1 Market Renewal Program

The MRP will bring about key changes to the wholesale market with the objective of improving efficiency, competition, and transparency.[125] These changes are aimed at addressing many of the inefficient elements unique to the Ontario market. Under the program, three key changes to the market will be:

1) Replacement of the Two-Schedule System (2SS) with a single schedule market, reducing the need for out-of-market payments such as Congestion Management Settlement Credits (CMSC).
2) Introduction of the Day-Ahead Market (DAM), which will improve operational certainty for the IESO by reducing financial risk for market participants.
3) Better optimization of scheduling and dispatching resources through the Enhanced Real-Time Unit Commitment (ERUC) program.

These changes are intended to help address two key inefficiencies in the current market design.

First, the single schedule market is aimed at alleviating inefficiencies associated with the uniform price and the 2SS. Ontario currently uses a province-wide uniform price for settlement instead of locational prices. In its first major review of the electricity market shortly after market opening, the Panel highlighted the uniform price as a key market problem.[126]

The 2SS with CMSC payments can distort the incentives for some participants to respond efficiently in the market, at times creating a disconnect between the price that reflects actual system needs and the payment opportunities available to a market participant. The 2SS works by balancing the market two separate times through an unconstrained schedule and a constrained schedule using different parameters. Constrained schedules

[125] The Market Renewal Program's mission statement is: "Market Renewal will deliver a more efficient, stable marketplace with competitive and transparent mechanisms that meet system and participant needs at lowest cost" (see also, the IESO's Market Renewal: Mission and Principles).

[126] See MSP Report 1, 2002.

Ontario Energy Board

must be formulated in time to issue relevant dispatch instructions for the dispatch interval to which they apply. Unconstrained schedules and prices for a given dispatch interval are presently calculated ex-post, using the most accurate data available for that interval, and initialized with resource-level data determined for the end of the preceding dispatch interval.[127] When physical constraints like transmission limits require some market participants to receive a dispatch instruction in the constrained schedule that is different from the former, that market participant is eligible to receive a CMSC payment. This design opens the door for gaming opportunities and undermines the objective of dispatch efficiency.

In past reports, the Panel has outlined multiple areas where the 2SS with CMSC payments creates misaligned incentives which cause inefficiencies:

- Differences between the uniform price paid by loads and the true (locational) price encourages excess/under consumption depending on the price sensitivity of the load.[128]
- When the uniform price paid by exporters is lower than the true local cost of generation, traders may export power to a lower cost jurisdiction resulting in more demand being served from the higher cost area.[129]
- The uniform price dampens valuable locational signals for long-term investment and retirement. For example, locational prices reward generators with additional profits for building in areas with supply shortages (and high prices). With a uniform price, generators are indifferent to where they build and have no incentive to build according to system locational needs.[130]
- The pay-as-offer nature of CMSC undermines participant's incentive to offer efficiently (at cost), and instead encourages participants to offer above or below

[127] See Section 8.2.1 "Ex-post Prices for Each Dispatch Interval" of Chapter 7 of the Market Rules.

[128] If loads do not respond to the price differences between the uniform and true locational price, then these "allocative efficiency" losses will not arise.

[129] Trading promotes regional efficiency by pulling generation from the lowest cost areas within the region. The uniform price limits the consideration of intra-Ontario locational cost differences, allowing for "productive inefficiency" losses when power from higher cost areas is scheduled instead of lower cost areas.

[130] "Dynamic efficiency" may be eroded as locational signals for investment and retirement are reduced.

costs. This can lead to dispatch inefficiencies and unwarranted payments. The Panel has termed this behavior "nodal price chasing".[131]

The introduction of locational marginal prices is also anticipated to stimulate competition and efficiency by rewarding and incentivizing lower cost generation. Under the current regime with CMSC, there is limited incentive to improve the management of congestion when generators are compensated for lost imputed operating profits as implied by the market schedule. Additionally, the current system does not adequately signal or incentivize the market to respond to locational cost differences across Ontario. In Texas (ERCOT), a move from zonal prices to locational marginal prices was estimated to have reduced prices by 2%.[132] Similarly, the move to nodal prices in California in 2009 was found to improve dispatch of the gas fleet by 2%.[133]

Second, the DAM and ERUC programs are intended to improve the scheduling and commitment of dispatchable generation.[134] These programs will replace the Real-Time Generation Cost Guarantee program which compensates combined-cycle generators for certain start-up and fuel costs, out-of-market, using a non-competitive process.[135] Non-quick start units are then asked to offer and operate ignoring these costs. The intention of the program is to mitigate the risk of market participants not starting their generation units in times when they are uncertain they will be dispatched sufficiently to recover those costs. But this can result in productive inefficiencies in the short-run when demand is not served using the lowest cost resources due to offers not truly being reflective of generation cost. The program also acts to suppress market prices below efficient levels as it removes the incentives for these frequent price-setting generators to reflect fixed start-up costs into their offer prices. The program is designed to favor reliability by ensuring non-quick start resources are brought on-line during times of increased needs, but it suppresses prices at these very times. This weakens price signals and reduces rewards for other market participants to be available at these times.

[131] "Nodal Price Chasing" refers to the behavior of participants to offer just above or below the nodal price to maximize CMSC payments. If suppliers believe they will get constrained-on, they have incentive to offer as high as possible while still getting dispatched (offering just below the nodal price) to maximize their expected payment. Conversely, if they believe they will get constrained-off, they have incentive to offer as low as possible while still not getting dispatched (offering just above the nodal price). Similar incentives exist on the demand side. The root of the issue is CMSC payments are designed to compensate suppliers according to their offers, rather than a price determined through the competitive market (see also, Chapter 4.2 of MSP Report 7, 2005 and Chapter 3 of MSP Report 37, 2002).

[132] See "Did the introduction of a nodal market structure impact wholesale electricity prices in the Texas (ERCOT) market?" by Zarnikau, et al. (2014).

[133] See "Measuring the Benefits of Greater Spatial Granularity in Short-Term Pricing in Wholesale Electricity Markets" by Wolak, Frank (2011).

[134] See Market Renewal Program: Energy Business Case (October 22, 2019).

[135] The DAM and ERUC programs will also replace the day-ahead commitment program (DACP). The DACP is also designed to compensate for these costs, but uses a more competitive process and three part offers for start-up, speed-no-load and incremental energy costs.

Ontario Energy Board

The DAM creates a financially binding Day-Ahead Market which provides more certainty around next-day operations, improving reliability and reducing the need for costlier out-of-market actions. The ERUC program is intended to improve efficiency by optimizing the scheduling of resources over multiple hours. When creating the optimized schedule, ERUC should account for key generator characteristics such as minimum loading points. Under the current design, the optimization algorithm looks at each hour in isolation and does not consider some of these key generator characteristics. This results in the need for out-of-market actions which are costlier and less competitive.

The IESO anticipates that 18 of the previous Panel market design recommendations will be addressed through the Market Renewal Program. To this end, the Panel intends to release an MRP pre-deployment report by early 2025 to set out its plans to:

- Assess market efficiency and competition, consistent with its mandate outlined in OEB By-Law #2, as the wholesale market undergoes its biggest stepwise change since market opening;
- Following deployment, evaluate how MRP has addressed the market inefficiencies raised in at least 18 past MSP recommendations where the MRP program was identified as the remediation measure for the underlying issue; and
- Identify key indicators of MRP's success and adapt the MSP's market monitoring program accordingly, drawing from the practices of other wholesale market monitoring programs in jurisdictions with similar design features.

Chapter 3 Section 3.06

Ministry of Energy

Independent Electricity System Operator—Market Oversight and Cybersecurity

1.0 Summary

The Independent Electricity System Operator (IESO) operates the wholesale electricity market (electricity market). This includes receiving competitive price offers from power generators and electricity importers to supply electricity.

Ontario power generators generally set their offers in order to recover their marginal costs for producing electricity (i.e., the costs of the fuel (gas), labour used and other variable costs). At the same time, the IESO receives bids from a small number of large industrial consumers and out-of-province electricity importers indicating how much electricity they are willing to consume and at what price. The IESO chooses the power generators with the lowest-price offers to supply the electricity needed to meet consumer demand. A new market clearing price for electricity is set every five minutes, and the average of the 12 prices set per hour is the Hourly Ontario Energy Price charged to consumers.

Since 2015, the IESO has also been responsible for long-term planning for electricity and procuring the generation capacity Ontario needs. Procurement is done through signing contracts with electricity power generators. These contracts provide guaranteed payments that compensate generators for building generation equipment (for example, nuclear and gas plants) and maintaining it.

Responsibility for oversight of the electricity market is shared by the Ontario Energy Board (OEB) and the IESO as follows:

- The IESO is responsible for fixing weaknesses and flaws in the design of the market. The **IESO's Market Assessment and Compliance Division (IESO Oversight Division)** monitors and investigates suspicious activity by market participants signalling they may be breaking market rules, and fines rule-breakers. (Market rules originate in the *Electricity Act, 1998*, and are intended to ensure that the wholesale sale and purchase of electricity and ancillary services are efficient, competitive and reliable. They include provisions for making the rules; conveying electricity through the grid; authorizing who can participate in the market; selling, purchasing and dispatching electricity; resolving disputes; and monitoring, surveilling and investigating the activities and conduct of market participants.)
- The OEB reviews the ratepayer impact assessment that the IESO provides before the IESO implements a change to the design of the market. The OEB can revoke any market rule

and simplify what the Market Surveillance Panel has reported.

In addition, we did a jurisdictional scan and engaged with the current head of the Market Surveillance Administrator in Alberta, the former head of the Market Surveillance Administrator in Alberta and the IESO Oversight Division in Ontario, and the head of an external oversight body for the New York Independent System Operator.

We engaged an expert with knowledge of the fields of electricity and energy to assist with interpretation of technical information that we reviewed as part of this audit and to provide knowledgeable insight and perspective on the issues we identified.

4.0 Detailed Audit Observations—Market Oversight

As explained in **Section 2.4**, ratepayers' bills have an electricity charge that is made up of the global adjustment and the market price. In addition, there is a regulatory charge through which the costs of reliability programs operated by the Independent Electricity System Operator (IESO) are recovered.

In 2016, ratepayers paid about $12.3 billion in global adjustment and an additional $2.5 billion for electricity bought as a commodity on the market (i.e., market price), as well as about $500 million for the reliability programs.

The Ontario Energy Board has oversight responsibility for about 29% of the $12.3-billion global adjustment (or $3.5 billion), which is paid to Ontario Power Generation. The remaining 71%, or $8.8 billion, is paid to generators under long-term contracts procured mostly by the former Ontario Power Authority that on January 1, 2015, was merged with the IESO. The IESO has oversight responsibility for about $500 million relating to the reliability programs.

In **Section 4.1**, we present our findings that relate to Ontario Energy Board oversight of IESO reliability programs governed by market rules and explain how the Ontario Energy Board could have done more to protect ratepayers' interests. In **Section 4.2**, we discuss the impacts of the government's decision to implement the Industrial Conservation Initiative, which allows large industrial ratepayers to reduce the amount of global adjustment they pay.

4.1 The IESO and Ontario Energy Board Could Have Done More to Support the OEB Panel's Recommendations

Under the *Electricity Act, 1998*, the IESO must give the Ontario Energy Board an assessment of the impact on ratepayers of any approved changes to market rules before the IESO implements them. The Ontario Energy Board has the authority to revoke the changes to market rules and send them back to the IESO for further consideration. The Ontario Energy Board, however, cannot order that the IESO make specific changes to market rules. Also, the IESO is not required to make changes or reapprove market rules revoked by the Ontario Energy Board. The Ontario Energy Board has never revoked a market rule change approved by the IESO Board.

The OEB Panel has made numerous recommendations to the IESO Board relating to the Real-Time Generation Cost Guarantee Program (shortened in this report to the Standby Cost Recovery Program) and Congestion Management Settlement Credits (shortened in this report to the Lost Profit Recovery Program):

- In 2010, 2011, 2014, 2015 and 2016, it recommended that the Standby Cost Recovery Program be reviewed, reassessed, justified or scaled back, and questioned if the program needs to be retained. As detailed in **Section 4.3**, this Program on average pays gas generators about $60 million per year and, according to an OEB Panel estimate, if the

IESO eliminates the reimbursement of certain operating and maintenance costs, the cost of the Program would be reduced by approximately $30 million annually.

- In almost all of its 28 reports (between 2002 and 2017), the OEB Panel expressed concerns about or recommended changes to the Lost Profit Recovery Program. As detailed in **Section 4.4.2**, this program on average pays market participants about $110 million per year, and, according to the OEB Panel, its weaknesses have allowed market participants to offer or bid prices into the market not based on actual costs or electricity supply needs but for the sole purpose of getting payments from the program.

These programs are governed by market rules, and their costs are charged to ratepayers through the regulatory charge on ratepayer bills. In the cases where the OEB Panel has concerns, the Ontario Energy Board has never revoked and sent back to the IESO for reconsideration a market rule change.

The OEB Panel has also pointed out that gas generators and others that have a direct and substantial financial interest in IESO programs like the Standby Cost Recovery Program influence the process that the IESO uses to change market rules. In this situation, the Ontario Energy Board's responsibility to protect ratepayers' interests should be even more heightened.

We made similar observations in our *2011 Annual Report* (see **Section 3.02** on our audit of regulatory oversight of the electricity sector). In our 2013 follow-up of the 2011 audit (see **Section 4.02** of our *2013 Annual Report*), the Ontario Energy Board informed us that in 2011, the Board began a correspondence with the IESO regarding the recommendations the OEB Panel made in its report to the IESO and that it requested and received in writing the following information from the IESO:

- steps the IESO intends to take in response to any recommendations made to it in the OEB Panel report;
- estimated timelines for completion of those steps; and
- whether, in the IESO's view, any actions or market rule amendments beyond those noted in the OEB Panel's report should be taken.

Based on this information provided to us in 2013 by the Ontario Energy Board, we concluded that our recommendation had been substantially implemented. However, during our 2017 audit, we found that the IESO has not always taken all the steps it could to meaningfully implement the OEB Panel's recommendations pertaining to the Standby Cost Recovery and the Lost Profit Recovery programs.

RECOMMENDATION 1

To ensure that ratepayers' interests are protected and that recommendations made by the Ontario Energy Board Market Surveillance Panel to improve market rules are addressed, we recommend that the Independent Electricity System Operator (IESO):

- implement the Ontario Energy Board Market Surveillance Panel's (OEB Panel) recommendations in an effective and timely way; and
- where the OEB Panel submits a report to the Independent Electricity System Operator that contains recommendations relating to the misuse, abuse or possible abuse of market power, the IESO should use its authority to amend the market rule immediately and submit it to the Ontario Energy Board for its review.

IESO RESPONSE

The IESO supports the OEB Panel's work and acknowledges the recommendation made by the Auditor General. The IESO carefully considers every OEB Panel recommendation and the OEB Panel's underpinning analysis, and responds to each recommendation outlining the actions it will take in a letter directed to the Chair and CEO of the Ontario Energy Board. The IESO has acted on a number of the recommendations made by the OEB Panel in the past and has made a number of market rule amendments as a result. The IESO will further continue to analyze and assess OEB Panel recommendations and consider possible amendments to market rules to address those recommendations, while also balancing the need to ensure the reliability of the electricity network, to consider the impact upon market design, including potential unintended adverse effects, and to assess the ability of the IESO and market participants to implement the change.

Where the OEB Panel submits a report to the IESO that contains recommendations related to market power, the IESO will take the action required of it under the *Electricity Act, 1998*,including amending the market rules where so ordered by the Board.

RECOMMENDATION 2

To ensure that ratepayers' interests are protected and that recommendations made by the Ontario Energy Board Market Surveillance Panel (OEB Panel) to improve market rules are addressed, we recommend that the Ontario Energy Board (OEB) use its legislative authority to revoke and refer a market rule amendment back to the Independent Electricity System Operator (IESO) for further consideration when the OEB's review determines that an amendment to the market rule is not in the best interest of ratepayers, having regard to the fact that it does not address the Market Surveillance Panel's recommendations. The OEB should continue to revoke and refer such a market rule amendment back to the IESO until it is satisfied that the market rule amendment is in the best interest of ratepayers.

ONTARIO ENERGY BOARD RESPONSE

The Ontario Energy Board (OEB) agrees with the importance that the Auditor General attaches to outcomes that are in the best interests of ratepayers. The OEB supports the recommendations of its OEB Panel, and will continue to use the tools at its disposal to signal that support while respecting its own mandate and processes and the authority and responsibilities of other agencies.

Since 2011, the OEB has regularly corresponded with the IESO regarding the recommendations the OEB Panel makes in its reports. When the OEB renewed the IESO's licence in 2013, a new licence condition was included that requires the IESO to make annual filings to the OEB on the status of actions taken further to recommendations in OEB Panel reports, including the rationale for not taking action where a recommendation remains outstanding.

The OEB will continue to work with the IESO to ensure that high-priority recommendations made by the OEB Panel are appropriately addressed in a timely manner.

OFFICE OF THE AUDITOR GENERAL RESPONSE

Although the OEB obtains annual filings from the IESO on the status of actions taken on the OEB Panel's recommendations, we noted that these status updates do not meaningfully address the recommendations pertaining to the Standby Cost Recovery and Lost Profit Recovery programs.

RECOMMENDATION 3

To ensure that ratepayers' interests are protected and that recommendations made by the Ontario Energy Board Market Surveillance Panel (OEB Panel) to improve market rules are addressed, we recommend that the Ministry of Energy review the legislative power and authority of the Ontario Energy Board to conduct a review of a market rule on its own motion, and to consider expanding its authority under the *Electricity Act, 1998*, when misuse and abuse of a market rule is brought forward by the OEB

Panel and is not effectively being addressed by the Independent Electricity System Operator (IESO) in a timely manner.

MINISTRY RESPONSE

The Ministry of Energy supports the Ontario Energy Board (OEB) and the IESO in the important roles they play to ensure that Ontario's electricity market operates efficiently.

The Ministry, in consultation with both the OEB and the IESO, will review the *Electricity Act, 1998*, regarding the market rule approval process. The Ministry will also review the authority of the OEB.

4.2 Government Not Transparent about the Effect of Expanding the Industrial Conservation Initiative

4.2.1 Overview

The government introduced the Industrial Conservation Initiative (ICI) to provide large industrial ratepayers with an incentive to reduce their consumption when the demand for electricity is at its peak. The government announced at the time of its launch in 2011 that by encouraging less consumption, the ICI could reduce the need to procure new generation resources. However, new generation resources have been procured since 2011.

The incentive the ICI provides is a reduction in the amount of global adjustment eligible ratepayers have to pay each month (recall from **Section 2.4** that the global adjustment is the larger of the two components of a ratepayer's electricity charge, the other being the market price of electricity). Under the ICI, an eligible industrial ratepayer has its global adjustment charge reduced in accordance with its portion of the overall provincial demand for electricity in the five hours of the year demand is at its highest.

To illustrate how this works, **Figure 7** presents hypothetical ratepayer data, and **Figure 8** shows the calculations.

Figure 7: Hypothetical Data for an Industrial Ratepayer Eligible for the Industrial Conservation Initiative

Prepared by the Office of the Auditor General of Ontario

5 Hours With Highest Demand	Ratepayer's Demand (MW)	Overall Provincial Demand (MW)
July 1, 5–6 p.m.	5.2	23,000
July 12, 4–5 p.m.	5.5	22,500
August 22, 5–6 p.m.	5.7	23,800
August 23, 3–4 p.m.	5.1	23,500
September 4, 2–3 p.m.	5.8	24,000
Total	**27.3**	**116,800**

The electricity charge for the hypothetical industrial ratepayer in this example will be the market price plus $255,366 each month. Once the industrial ratepayer's global adjustment amount is calculated, the payment amount is fixed for the whole year, regardless of the amount of electricity the industrial ratepayer actually consumes at any time other than the five hours provincial peak demand is at its highest.

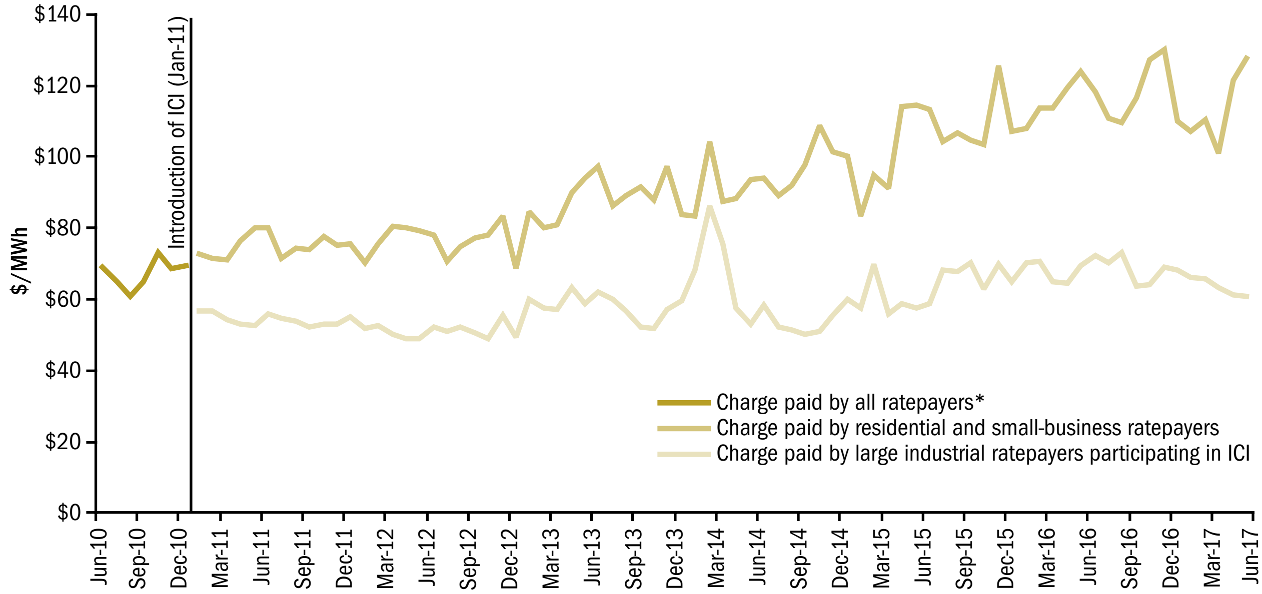
The more the industrial ratepayer reduces its electricity consumption during the five hours of highest peak demand, the lower its fixed monthly global adjustment charge will be. If the industrial ratepayer reduces consumption to zero during those five hours, the global adjustment component of its monthly bill will be eliminated altogether, and it pays just the market price for electricity every month for a full year. This can be a very significant discount—as **Figure 4** shows, for 2016, the global adjustment made up 85% (9.66 cents per kilowatt hour [cents/kWh] of the total 11.32 cents/kWh) of Ontario ratepayers' electricity charge.

To be eligible when the ICI was first launched in 2011, an industrial ratepayer's monthly peak demand had to average out, over the 12 months from May 1 to April 30, to at least 5 MW. Since then, eligibility was expanded three times (that is, the minimum average monthly peak demand was lowered three times), as follows:

- July 2015—from 5 MW to 3 MW;
- January 2017—from 3 MW to 1 MW; and

Figure 9: Electricity Charge Before and After the Introduction of the Impact of Industrial Conservation Initiative (ICI)

Source of data: Independent Electricity System Operator (IESO)



* The Industrial Conservation Initiative (ICI) split the charge paid by all ratepayers into two charges: one for large industrial ratepayers participating in ICI, and a second one paid by all other (residential and small-business) ratepayers.

Lowered peak demand reduces the need for supply resources and ultimately the projection for electricity system cost. The Independent Electricity System Operator (IESO) estimates that ICI reduced peak demand by about 1,300 megawatts in 2016. ICI supports a fair cost allocation framework where consumers who are contributing the least to peak demand pay a smaller portion of these related long-run costs. It is also worth noting that the IESO publishes on its website the allocation of global-adjustment costs each month, as well as the consumption for each class of consumer.

The Ministry would also like to clarify that the benefit for residential and small-business consumers will not be influenced by ICI expansion. The Ontario Fair Hydro Plan reduced electricity bills for residential consumers by an average of 25% and will hold any increases to the rate of inflation for four years.

4.3 The IESO Continues to Administer the Standby Cost Recovery Program Despite Reasons Not To

The Standby Cost Recovery Program pays generators for costs to start and then run their equipment while on standby to supply electricity. The generators enrolled in the Program are gas plants (prior to their closures by 2014, coal-fired power plants were also enrolled), whose equipment needs to be warmed up, running and ready to go so the IESO can dispatch them to supply electricity very quickly should demand spike suddenly or unexpectedly.

When the Program was introduced in 2003, it reimbursed generators only for their fuel costs for being on standby. In 2009, the program was expanded to also reimburse them for their additional operating and maintenance costs while on standby.

4.3.1 The IESO Has Not Implemented the OEB Panel's Recommendation to Reassess and Change the Standby Cost Recovery Program

The OEB Panel reported in 2015 that the electricity supplied by the gas generators that claimed $61 million in costs in 2014 under the Standby Cost Recovery Program was used for less than 1% of the hours to meet Ontario demand.

The OEB Panel was concerned that the Program is overused, at a time when Ontario regularly finds itself in surplus power conditions and is a net exporter of electricity.

OEB Panel reports in 2010 and 2011 recommended that the IESO revise (2010) and reassess (2011) whether the Standby Cost Recovery Program is providing a net benefit for ratepayers, which the IESO did not do. A 2014 OEB Panel report recommended that the IESO provide detailed analysis of market data to justify the need for the Standby Cost Recovery Program's continued existence, which the IESO did not provide. In its 2016 report, the OEB Panel again questioned the need for this Program and why the IESO does not stop reimbursing gas generators for certain operating and maintenance costs, which, according to the OEB Panel, would save ratepayers millions.

The IESO has asserted that the Program is still needed for reliability purposes. However, the IESO has yet to provide any detailed analysis to justify the need for the Standby Cost Recovery Program and its concerns about reliability if the program was discontinued.

4.3.2 Changes to the Standby Cost Recovery Program Do Not Encourage Generators to Be Efficient—Costing Ratepayers More than Necessary

In 2009, the type of costs reimbursed by the Standby Cost Recovery Program expanded from just gas and coal generators' standby fuel costs to their maintenance and operating costs as well.

This change has reduced the incentive for gas and coal generators (prior to their closure) to try to operate more efficiently by managing costs. Costs associated with the Standby Cost Recovery Program are directly passed through to ratepayers.

In 2015, the OEB Panel reported that ratepayers would save about $30 million annually if the Program stopped reimbursing gas generators for certain maintenance and operating costs.

In addition to the savings, this change would provide an incentive for generators to operate more efficiently and minimize these costs, as they would no longer be automatically reimbursed.

The IESO has not implemented the Panel's recommendations. As a result, the Program continues today to reimburse gas generators for their maintenance and operating costs.

4.3.3 Nine Gas and Coal Generators Have Claimed $260 Million in Ineligible Costs under the Program—About $168 Million Recovered

In response to a suggestion by the OEB Panel, in 2012 the IESO Oversight Division started auditing the costs claimed by nine of the 11 gas and coal generators registered under the Standby Cost Recovery Program at that time. Since then, the number of generators registered under the Program has increased to 17. The audits conducted by the Oversight Division identified almost $260 million in possible ineligible cost claims out of a total of about $600 million paid out to gas and coal generators under the Program. The Oversight Division recovered about $168 million (about two-thirds) of the $260 million through settlements with individual generators, and at the time of our audit it was trying to recover another $10 million that generators were disputing. **Figure 10** shows the results of the audits.

Only fuel, maintenance and operating costs that gas and coal generators incur for being on standby are eligible to be claimed under the Standby Cost Recovery Program. The IESO was not reviewing all

Figure 10: Results of Audits of Costs Claimed by Nine Generators under the Standby Cost Recovery Program

Source of data: Independent Electricity System Operator (IESO)

Generator*	Years of Submissions Covered by Audits	Total Claims Paid ($ million)	Ineligible Costs ($ million)	Ineligible Costs % of Total Paid	Ineligible Costs Recovered Total Recovered ($ million)	Ineligible Costs Recovered % of Ineligible Costs Recovered
Company A	2009–15	240.0	162.1	68	110.0	68
Company B	2006–15	147.0	50.9	35	22.0	43
Company C	2006–15	78.0	22.7	29	17.4	77
Company D	2008–14	72.0	2.1	3	1.3	62
Company E	2010–12	23.0	7.5	33	7.5	100
Company F	2009–12	17.0	6.5	38	3.5	54
Company G	2010–12	7.9	4.1	51	2.7	66
Company H	2006–12	3.6	2.3	64	2.3	100
Company I	2006–15	2.4	1.2	50	0.8	67
Total		**590.9**	**259.4**	**44**	**167.5**	**65**
Average				**41**		**71**

* Audit information is designated confidential information under the provisions of the Market Manual, Market Rules and the *Electricity Act, 1998*. We therefore refer to generators in this figure anonymously as "Company A," "Company B," and so on.

cost claims submitted by generators before paying. Generators claimed thousands of dollars annually for staff car washes, carpet cleaning, road repairs, landscaping, scuba gear and raccoon traps, which have nothing to do with running power equipment on standby. For example, the Oversight Division found that one generator claimed about $175,000 for coveralls and parkas at one facility over a two-year period.

In October 2017, the OEB Panel released a public report detailing the results of its investigation of the Goreway Power Station's misuse of the Standby Cost Recovery and Lost Profit Recovery programs. Through review of Goreway's internal records and documents and other information, the OEB Panel found the following:

- Goreway claimed $17 million in costs for which it could not provide any supporting records.
- Goreway claimed an extra $25,000 in costs each time it started its power equipment. The total of payments it received under the Standby Cost Recovery Program as a result was $5 million.
- Goreway claimed ineligible costs that included $6.5 million for gas to fuel a steam turbine that does not consume any gas and $300,000 for landscaping.
- Goreway provided to the IESO Oversight Division, which was conducting its own audit, documents containing fictitious costs. Some related to equipment parts worth about $27 million that Goreway had no intention of purchasing and that would be redundant.

4.3.4 Electricity Bought at Higher Cost from Gas Generators Because Gas Generators Used the Standby Cost Recovery Program to Suppress the Market Price

Besides filing ineligible claims for costs that have nothing to do with fuel, maintenance or operating costs, some gas generators have filed Standby Cost Recovery Program claims for their costs to produce electricity, instead of reflecting those costs in their offer to sell electricity to the market (those costs would then be recovered through the market price, as explained in **Section 2.4**). Only incremental costs to run equipment on standby should be claimed under this Program, not generators' costs to produce electricity for sale to the market. The OEB Panel reported on this in 2010.

Claiming their costs to produce electricity under the Standby Cost Recovery Program enabled gas generators to lower the price they offered to be chosen to produce electricity. **Figure 11** shows how the market price is suppressed when gas generators misuse the Program by claiming their costs to produce electricity.

This has led to the IESO's inefficiently selecting which gas generators will produce electricity (that is, the IESO buys electricity from a gas generator that produces it for a higher overall cost), resulting in a depressed market price and an inflated global adjustment.

According to a Panel estimate, the market price for electricity from January to April 2010 was artificially lower by as much as 85% than it would have been if generators had not claimed their costs from the Standby Cost Recovery Program. The OEB Panel also estimated that between December 9, 2009, and April 30, 2010, the loss associated with the IESO's buying electricity from one gas generator that produced it for a higher overall cost was about $16.3 million.

The OEB Panel has not done any similar reviews since 2010.

4.3.5 Electricity Costs Higher Because Gas Generators Do Not Continuously Run Their Equipment When on Standby

Another way reported by the OEB Panel that gas generators can raise electricity costs is by shutting down their equipment while on standby, only to restart it again within two hours. This allowed generators to submit their equipment start-up costs under the Standby Cost Recovery Program. Running their equipment continuously would have saved money, but generators could not have then submitted the additional start-up costs for reimbursement. The OEB Panel reported that in summer 2010, nearly all of the $19 million in extra electricity costs charged to ratepayers was because of this practice.

RECOMMENDATION 5

To protect ratepayers' interests and to improve the transparency of the decisions of the Independent Electricity System Operator (IESO),

Figure 11: Standby Cost Recovery Program—How Market Price Is Suppressed[1]

Prepared by the Office of the Auditor General of Ontario

1. This figure is for demonstration purposes only and does not reflect an actual transaction that has occurred.
2. Based on an artificially lower offer, Generator 1 would be selected by the Independent Electricity System Operator (IESO) to produce electricity over Generator 2, even though Generator 1's cost to produce electricity is $50 higher. Generator 1 recovers $100 worth of costs through the Standby Cost Recovery Program, which is charged directly to ratepayers.

we recommend that the IESO provide a detailed analysis to the Ontario Energy Board Market Surveillance Panel (OEB Panel) to support its assertion that the Standby Cost Recovery Program is necessary to ensure a reliable supply of electricity for Ontarians.

IESO RESPONSE

In 2018, the IESO will present to the OEB Panel a detailed analysis supporting the rationale for its previous assertions to the OEB Panel that a real-time generator commitment mechanism (currently the Real-Time Generator Cost Guarantee Program, referred to in this report as the Standby Cost Recovery Program) is necessary to allow the IESO to comply with North American power system reliability standards and ensure a reliable supply of electricity for Ontarians.

RECOMMENDATION 6

To ensure that ratepayers are not charged for unnecessary costs, we recommend that, if the Independent Electricity System Operator does not cancel the Standby Cost Recovery Program, it fully implement the Ontario Energy Board Market Surveillance Panel's (OEB Panel) recommendations and not reimburse generators for operating and maintenance costs under the Program.

IESO RESPONSE

The IESO acknowledges the recommendation made by the Auditor General and notes that the total costs of the Real-Time Generator Cost Guarantee Program (referred to in this report as the Standby Cost Recovery Program) have fallen from $61 million in 2014 to $23 million in 2016. In light of OEB Panel recommendations, the IESO implemented a new cost recovery framework for this Program on August 1, 2017. Under this new framework, the values for 14 of 15 eligible costs are now set and approved in advance of participating in the Program for each program participant. This change introduced transparency and removed the potential for overpayments and the need for after-the-fact audits for these components. One cost component is still subject to audit, as it cannot be pre-approved, but this cost component was not identified as an issue in the Standby Cost Recovery Program audits.

The IESO acknowledges issues with the current Standby Cost Recovery Program in our responses to previous OEB Panel reports and has committed to replace it. The IESO has initiated a $200-million comprehensive program to fundamentally overhaul Ontario's electricity market. Market Renewal is estimated to result in up to $5.2 billion in savings, the majority of which is estimated to be realized by ratepayers (see "The Future of Ontario's Electricity Market, A Benefits Case Assessment of the Market Renewal Project," **http://www.ieso.ca/-/media/files/ieso/document-library/engage/me/benefits-case-assessment-market-renewal-project-clean-20170420.pdf?la=en** and **http://www.ieso.ca/sector-participants**). The Enhanced Real-Time Unit Commitment initiative of Market Renewal will replace the current Standby Cost Recovery Program with a transparent and competitive mechanism that will ensure reliability through a more efficient commitment of resources near real time.

4.4 The IESO Continues to Pay Market Participants under the Lost Profit Recovery Program without Addressing the Program's Flaws and Weaknesses

4.4.1 Overview

The Lost Profit Recovery Program was established in May 2002. The Program compensates market participants if they lose money from a change that the IESO makes to the way it has scheduled power to be dispatched. The need to make these interventions, and then to pay compensation, is built into Ontario's market design: one scheduling approach considers system constraints (such as transmission line capacity) to determine which generator produces power, but another scheduling approach, based on an unconstrained (competitive and open) transmission system, is used to determine market price.

One of the reasons for the IESO's intervention in the market schedule is to keep transmission lines from being overloaded. Another is to fill an unexpected shortfall in supply. Here are three scenarios where this program comes into play:

- Generator A has successfully offered to supply electricity for the market for a given time period. However, the IESO must order it to stop supplying electricity because of a potentially damaging overload in the transmission lines. Generator A loses money as a result. The Program compensates Generator A for the lost profit.
- There is a shortfall in electricity because the IESO has ordered Generator A to stop supplying. The IESO orders Generator B, whose bid to supply electricity was too high to be chosen, to supply the shortfall at the market price. Generator B's costs to supply the electricity are higher than the market price. The Program compensates Generator B for the difference between its costs to supply electricity and the market price.
- A large industrial consumer offers, for a price, to reduce its high demand for electricity at a given time. The IESO cannot accept this offer as it already planned to supply the electricity, and sending the supply through the transmission lines without the consumers needed to draw down the supply would cause a potentially damaging overload in the transmission lines. The IESO orders the large industrial consumer to keep its demand high, and the large industrial consumer loses money as a result. The Program compensates the large industrial consumer for this loss.

Between 2002 and the end of 2016, market participants have been paid about $1.6 billion, or $110 million annually on average, under this Program.

4.4.2 The OEB Panel Has Reported the Potential for Participants to Misuse Market Rules under the Lost Profit Recovery Program

A 2016 OEB Panel special report on the Lost Profit Recovery Program states: "Since market opening, no element of Ontario's wholesale electricity markets has attracted the attention and concern of the Market Surveillance Panel [OEB Panel] more than [Lost Profit Recovery Program] payments."

Even before the market opened in 2002, the OEB Panel reported that the market participants could offer or bid prices not based on actual costs or supply needs but for the sole purpose of getting payments from the Program.

Soon afterwards, the OEB Panel was reporting not just on the potential for this to happen, but also on actual situations of market participants misusing the program. The OEB Panel began reviewing the payments market participants received under the Program after the market opened in 2002, and also investigating the behaviour of certain participants. The results of five investigations, some of which took from two to four years to complete, have been made public by the OEB Panel. These are summarized in **Figure 12**.

The OEB Panel has also reported on large payments made under the Program. As of the end of 2015, about $500 million of the total $1.5 billion paid out went to market participants in northwestern Ontario. The generators in that region represent less than 5% of Ontario's generation capacity, and the demand for electricity in that region has fallen. The concern is that the market participants involved may be submitting bids and offers into the market to create the conditions under which they can claim lost profits that they may not have incurred.

Figure 12: Investigations into the Lost Profit Recovery Program Reported by the Ontario Energy Board (OEB) Panel[1]

Source of data: Ontario Energy Board (OEB)

Year	Market Participant	Summary of Results
2016	Goreway Power Station	A substantial portion of the $11 million paid to Goreway under the Program between June 2009 and June 2012 is believed by the OEB Panel to have resulted from misuse of the rules.
2015	Resolute Forest Products Inc.[2]	During an eight-month period in 2010, the company misused market rules to gain $20.4 million. The OEB Panel reported that the company used one of the Panel's past reports, which recommended that the IESO fix the rules, to learn how to misuse the rules. As a result of a subsequent investigation by the IESO's Oversight Division, Resolute repaid $10.6 million.[3]
2014	Greenfield Energy Centre	Between December 2010 and August 2011, the company misused market rules to gain $432,000. Greenfield Energy later repaid the amount in full to the IESO.
2012	TransAlta Energy Marketing Corp.	The investigation exposed weaknesses in certain market procedures, which the OEB Panel recommended that the IESO fix.
2012	West Oaks Energy NYINE, LP	The investigation exposed weaknesses in certain market procedures, which the OEB Panel recommended that the IESO fix.

1. The only other investigation conducted by the OEB Panel since 2003 did not relate to the Lost Profit Recovery Program (it was a complaint about possible withholding by Ontario Power Generation of coal-fired generation).
2. In 2011, Abitibi Bowater Inc. (Abitibi) was renamed Resolute Forest Products Inc. At the time, Abitibi owned and operated Bowater Canadian Forest Products Inc. and Abitibi-Consolidated Company of Canada.
3. The OEB Panel does not have the authority to issue fines or sanctions against market participants. It can report and make recommendations, and refer the matter to the IESO Oversight Division. The Division can issue fines; however, it has to conduct its own independent investigation. For further discussion see **Section 4.7.5**.

As mentioned in **Section 4.3.3**, the OEB Panel released a public report detailing a generator's misuse of the Standby Cost Recovery and Lost Profit Recovery programs. The OEB Panel found that this generator received under the Lost Profit Recovery Program a large portion of $11 million for claimed lost profits that did not exist. The OEB Panel also reported that some of the IESO's fixes to the market rules that the generator misused may still leave the Program open for other generators to misuse.

The OEB Panel has analyzed the Program in almost all of its 28 reports and made several recommendations for the IESO to fix the rules' flaws that allow market participants to claim artificial losses. The Panel has also recommended that the IESO restrict this Program. The IESO has fixed some of the flaws, but sometimes not to the full extent recommended by the Panel. The IESO has otherwise responded to the OEB Panel that it is deferring making any major changes to the Program until the working group of its Market Renewal Initiative completes its work. However, changes resulting from this work will not be implemented for another five years. (See **Section 4.6.2** for more information on this working group.)

RECOMMENDATION 7

To ensure that ratepayers are not charged for unnecessary costs associated with the Lost Profit Recovery Program, we recommend that the Independent Electricity System Operator (IESO) implement the recommendations of the Ontario Energy Board Market Surveillance Panel (OEB Panel) regarding this Program.

IESO RESPONSE

The IESO acknowledges the recommendation made by the Auditor General and carefully considers every OEB Panel recommendation and the OEB Panel's underpinning analysis, and responds to each recommendation outlining the actions it will take in a letter directed to the Chair and CEO of the OEB. The IESO has acted on a number of the recommendations made by the OEB Panel related to Congestion Management Settlement Credits (referred to in this report as the Lost Profit Recovery Program) and has implemented more than a dozen market rule amendments regarding the Program. In light of the recommendations made by the OEB Panel over the years, the IESO will continue to consider the OEB Panel recommendations when assessing amendments to market rules while also balancing the need to ensure the reliability of the electricity network, to consider the impact upon market design including potential unintended adverse effects and to assess the ability of the IESO and market participants to implement the change.

The IESO has initiated a $200-million comprehensive program to fundamentally overhaul Ontario's electricity market. Market Renewal is estimated to result in up to $5.2 billion in savings, the majority of which is estimated to be realized by ratepayers (see "The Future of Ontario's Electricity Market, A Benefits Case Assessment of the Market Renewal Project," **http://www.ieso.ca/-/media/files/ieso/document-library/engage/me/benefits-case-assessment-market-renewal-project-clean-20170420.pdf?la=en** and **http://www.ieso.ca/sector-participants**). The Single Schedule Market (SSM) initiative of Market Renewal will eliminate the Lost Profit Recovery Program.

4.5 Market Participants Benefiting from Market Flaws Are Involved in Changing Market Rules and Market Design

4.5.1 Overview of the Market Rule Amendment Process

The IESO Board has the authority and responsibility to amend market rules. Anyone, including the IESO or market participants, can request an amendment to the market rules. Before the IESO Board approves any amendment, it is first reviewed by the IESO Technical Panel, appointed by the IESO Board, made up of members who are mostly industry and generators' representatives. **Figure 13** shows the most recent composition of the Technical Panel as of June 27, 2017.

The Technical Panel considers each proposed amendment and decides if:

- the amendment should not be adopted;
- the amendment should be adopted and recommended for IESO Board approval; or
- the amendment needs further clarification or stakeholder input and should then be resubmitted to the Technical Panel for reconsideration.

Figure 13: Composition of Technical Panel
Source of data: Independent Electricity System Operator (IESO)

Member*	Representation
1	Consumer
2	Energy-Related Business/Services
3	Natural Gas Industry
4	Independent Electricity System Operator (IESO)
5	Market Participant
6	Generator
7	Generator
8	Residential Consumer Group
9	Industrial Consumer Group
10	Electricity Wholesalers
11	Transmitters
12	Chair

* Number of members can fluctuate.

4.5.2 Gas Generators Are Involved in the Rule-Changing Process of the Standby Cost Recovery Program

As mentioned in **Sections 4.3.1** and **4.3.2**, the OEB Panel has repeatedly recommended that the market rules that govern the Standby Cost Recovery Program be changed. The OEB Panel specifically recommended that the IESO stop reimbursing gas generators for their maintenance and operating costs. The following is a chronology of key events relating to issues with the Standby Cost Recovery Program:

- 2011 and 2014—The OEB Panel recommends that the Standby Cost Recovery Program be reviewed to assess its benefits for ratepayers and whether it continues to be needed.
- 2012–2014—The IESO Oversight Division audits payments made between 2006 to 2015 under the Program and finds $260 million paid to gas and coal generators was for possibly ineligible costs.
- 2015—The OEB Panel again recommends that the IESO define the eligible costs more precisely.
- April 20, 2016—IESO management submits a proposal to its Technical Panel to amend the market rules governing the Standby Cost Recovery Program. The amendments are to clarify and better define the operating and maintenance costs eligible for recovery, and to reduce the scope and frequency of audits conducted by the IESO Oversight Division (because clarifying and better defining eligible costs will reduce or eliminate generator claims for ineligible costs).
- September 13, 2016—At a public meeting held by the Technical Panel, IESO management tells the panel that generators are continuing to submit ineligible cost claims, that IESO staff are burdened with having to review these claims, and that these costs need to be more clearly defined for generators. Generators tell the Technical Panel that the IESO has not sufficiently consulted them on the changes it is considering making to the Standby Cost Recovery Program. The Technical Panel votes six to four against recommending to the IESO Board that changes be made to the Standby Cost Recovery Program. The rationale provided by the six members voting no is primarily that IESO management has not allowed generators to review the proposed changes and provide input on the technical details supporting them.
- October 2016–March 2017—The IESO obtains input from gas generators on the technical details, revises its proposed changes and resubmits them to the Technical Panel.
- March 21, 2017—The Technical Panel votes seven to four (with one abstention) in favour of recommending the changes to the IESO's Board for approval.
- April 2017—The IESO Board approves market rule changes to better define and pre-approve costs that generators can claim and to reduce the scope and frequency of audits of generator cost claims under the Standby Cost Recovery Program.
- May 2017—IESO management says to the Technical Panel that involving generators in the process of drafting technical details that support market rules (as was done between October 2016 and March 2017) contravenes its usual procedures.

In reviewing these events, we were particularly concerned about the involvement of generators in the process of drafting technical details that support market rules. This involvement was apparently based simply on generators' assertion that they were not sufficiently consulted on the changes to the technical details that support market rules—yet such consultation is not a normal procedure.

At the time of our audit, the IESO had not meaningfully addressed the recommendations made by the OEB Panel, and gas generators continued to be reimbursed for their operating and maintenance costs under the Standby Cost Recovery Program. We noted as well that neither had the Ontario

Energy Board used its authority to revoke the IESO Board–approved changes to the Program and send the changes back to the IESO for reconsideration on the basis that they are not in the best interest of ratepayers.

4.5.3 Market Participants Are Heavily Involved in the Market Renewal Process

In 2016, the IESO started a Market Renewal Initiative (Initiative) to address known issues with the current market design. These issues relate to the fact that, over the 15 years the market has been in place, two different schedules have governed its operations. One scheduling sequence determines market price based on an unconstrained transmission system. The second scheduling sequence considers transmission constraints to schedule which generator produces power. The "two-schedule" system was intended to be only temporary when the market opened in 2002, but this problem has not been resolved to date. This system also prompted the need for the Lost Profit Recovery Program and has resulted in the inefficiencies that have been reported by the OEB Panel and that we have highlighted in **Section 4.4**.

The IESO stated in a 2017 report published as part of the Market Renewal Initiative that one area the Initiative will specifically address is changes to the Lost Profit Recovery Program. The IESO told us that it expects to implement these changes sometime in 2022.

A 23-member working group is leading the Initiative, advising the IESO on strategic, policy and market design issues. Its members represent generators, consumers and other stakeholders.

Figure 14 shows the make-up of the working group. Some of the members that are on the working group are representing companies that have been found by the OEB Panel and/or the IESO Oversight Division to have misused market rules. More specifically:

- Goreway (whose representative is co-chairing the Initiative)—was found by the OEB Panel to have claimed ineligible or fabricated costs under the Standby Cost Recovery Program totalling $89 million and took advantage of market rules that govern the Lost Profit Recovery Program to obtain a substantial portion of the $11 million it received for lost profits that were not incurred. (See **Section 4.4.2** for details.)
- Resolute Forest Products—was found by the OEB Panel to have obtained $20.4 million by misusing market rules that govern the Lost Profit Recovery Program and was found by the IESO Oversight Division to have broken market rules by repeatedly submitting false bids to withdraw electricity from the grid when

Figure 14: Members of the Market Renewal Initiative Working Group as of October 1, 2017
Source of data: Independent Electricity System Operator (IESO)

Representing Generators	Representing Consumers	Representing Other Stakeholders
Co-Chair/Goreway Power Station	Co-Chair/Tembec	EnerNOC
Brookfield Renewable Power	Ivaco Rolling Mills	HQ Energy Marketing
Vacant	Gerdau	NRStor
NextEra	Resolute Forest Products	Energy Storage Canada
Northland Power	Association of Major Power Consumers in Ontario	Alectra
Ontario Power Generation	Vacant	Market Surveillance Panel
TransCanada Energy	Power Consumer	Opus One Solutions
Association of Power Producers of Ontario	Canadian Manufacturers and Exporters	Peak Power Energy
		Milton Hydro

it could not do so and by defying the IESO's dispatch instructions. (See **Section 4.4**.)

The 23-member working group also includes three other organizations that have or are being investigated by the IESO Oversight Division for misusing market rules:

- a market participant that was being investigated by the IESO Oversight Division at the time of our audit for major breaches of market rules that govern the Lost Profit Recovery Program involving a potential $20 million in related payments;
- a market participant that submitted ineligible cost claims under the Standby Cost Recovery Program that the IESO Oversight Division estimated to be about $51 million (see **Section 4.3**); and
- a market participant that claimed ineligible costs under the Standby Cost Recovery Program totalling $7.5 million (see **Section 4.3**).

Audit information and the names of market participants under investigation are designated confidential under the provisions of the Market Manual, market rules and the *Electricity Act, 1998*. We therefore do not disclose the names of these market participants in our report.

We also noted that the representation of consumers in the working group is weighted in favour of high-volume electricity consumers, as opposed to medium- and low-volume electricity consumers.

RECOMMENDATION 8

To ensure that the Market Renewal Initiative (Initiative) considers and protects all ratepayers' interests, we recommend that the Independent Electricity System Operator (IESO):

- immediately prohibit representatives from companies that have been found by the Ontario Energy Board Market Surveillance Panel or the IESO Oversight Division to have misused IESO programs from participating in the Initiative working group;
- establish a minimum number of working group members representing low-power consumers and ensure that those positions are always filled; and
- publicly report in clear language how the results of the Initiative will be in the best interests of all ratepayers.

IESO RESPONSE

The IESO acknowledges the recommendations of the Auditor General and will continue to evaluate the membership of the working groups used for Market Renewal.

The IESO will also continue to ensure that its stakeholder engagement processes, including Market Renewal, seek representation from low-volume consumers where appropriate. The IESO's stakeholder engagement processes seek the input from a wide representation of participants—generators, traders, consumers, stakeholders, First Nations and Metis Peoples, communities, and the general public—and are guided by seven engagement principles that were put in place in November 2015 (see **http://www.ieso.ca/sector-participants/engagement-initiatives/overview/engagement-principles**).

One of the principles, which applies to Market Renewal, seeks to ensure adequate representation in each engagement of the public or those that have a tendency to remain silent or reluctant to engage. Where practical, a variety of engagement methods will be offered to provide flexibility to participate.

The IESO is also required by statute (the *Electricity Act, 1998*, S.O. 1998, c. 15, Sched. A, s. 188) to have a Stakeholder Advisory Committee that provides appointed stakeholder representatives with the opportunity to present advice and recommendations on key initiatives like Market Renewal directly to the IESO's independent Board of Directors and Leadership Team. Members include low-volume consumers (see **http://www.ieso.ca/-/media/files/ieso/document-library/sac/sac_tor.pdf**).

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

Market Surveillance Panel

Monitoring Report on the IESO-Administered Electricity Markets

for the period from
November 2012 – April 2013

January 2014

market prices. While higher market prices are neither “good” nor “bad”, a market price that is more reflective of the marginal cost of supplying the next megawatt is a desirable outcome. A constrained-off import is not physically capable of delivering the next megawatt of supply due to the physical transmission limitations in the area of the intertie. By including constrained-off imports in the unconstrained schedule and, consequently, in the determination of the MCP, supply which cannot physically deliver power (referred to as “phantom supply”) is nonetheless relevant in establishing the marginal cost of delivering the next megawatt of electricity.

Prior to the October 2012 Rule Change, 61% of all imports into the NW were constrained off, adding a significant amount of phantom supply to the unconstrained schedule. This had the effect of depressing the MCP relative to the actual cost of supplying the next megawatt of non-dispatchable demand, which would ultimately be supplied by constraining on a more expensive generator, or constraining off a more expensive load or export. Following the Rule Change, the quantity of phantom supply from imports in the NW has decreased, both in absolute and relative terms. The decrease in phantom supply has served to increase market prices, but has led to a MCP that is more reflective of the marginal cost of supply, a good market outcome.

The elimination of constrained-off CMSC payments has removed the incentive to chase nodal prices. Formerly, importers would chase the nodal price with below-cost offers, which inefficiently supressed the MCP. Importers now compete to deliver energy, not to get constrained off. As seen in Figures 3-6 and 3-7 above, this more desirable form of competition has driven import offers towards marginal cost. That, in turn, improves the quality of the MCP as an indicator of the marginal cost of supply, a good market outcome.

3.2 The Enhanced Day-Ahead Commitment Process and Generation Cost Guarantees

3.2.1 *Introduction*

Operating an electricity system reliably requires that sufficient generation capacity be available to meet demand at all times. System operators must have resources online and available to deal with changing demand and supply conditions. In the IESO-administered market, generators are paid the market price for the electricity that they inject into the grid.[90] When market prices are high, generators should be willing to produce. However, many generators incur significant costs to start up their facilities and, for equipment reasons, they must ramp to a minimum level of output (referred to as the "minimum loading point" or MLP) and remain online for a minimum period of time (referred to as the "minimum generation block run time" or MGBRT) before their units can be shut down. These generators face the risk that market prices might fall during the course of their minimum run, resulting in insufficient revenue to cover their start-up costs. To ensure that generators are willing to start up when needed, the IESO has developed cost guarantee programs for fossil-fueled non-quick start generators that minimizes their risk of exposure to such market price changes. Non-quick start generators are generation facilities that do not meet the IESO's definition of "quick start facilities" (these being facilities that are able to provide energy to the grid within 5 minutes of the IESO's request).

The IESO currently has two cost guarantee programs available for eligible non-quick start generation facilities: the real-time generation cost guarantee program (RT-GCG), which was introduced in 2003; and the generation cost guarantee program under the enhanced day-ahead commitment process (EDAC), which was introduced in 2011 and replaced the day-ahead generation cost guarantee program (DA-GCG) available under an earlier iteration of the day-ahead commitment process (DACP). The following are key features of each of these generation cost guarantee programs, which are also summarized in Table 3-4:

a. The RT-GCG[91] is a voluntary program that was introduced in 2003 and that remains in effect today. The guarantee covers start-up costs as well as costs over the generation facility's "minimum run-time", defined as the number of hours required for the generation facility to ramp from a cold start to its MLP and to complete its MGBRT. The generator will receive a payment under the program to the extent that the market revenues earned for output up to the facility's MLP to

[90] Most generators in the Province operate (and are compensated under) long-term contracts with the Ontario Power Authority or have the payment amounts for their output set by the Ontario Energy Board. Given the nature of the analysis conducted by the Panel, these arrangements have been ignored.

[91] See Market Manual 5.5, s. 1.6.4, "The Real-Time Generation Cost Guarantees" at http://www.ieso.ca/imoweb/pubs/settlements/se_RTEStatements.pdf. This program is sometimes referred to as the "Spare Generation On-line" program (SGOL). Rules relating to the RT-GCG program are set out in sections 2.2B, 5.7 and 6.3A of Chapter 7 of the market rules and in section 4.7B of Chapter 9 of the market rules.

the end of its MGBRT are less than the generator's submitted costs. One of the key features of the program is that the IESO schedules eligible generators under the RT-GCG without knowing the amount of their start-up costs; those costs are submitted to the IESO up to 16 business days after the end of a guaranteed run.

b. In 2006, the IESO introduced DACP, which included the DA-GCG program. Under the DA-GCG program, eligible generators would be scheduled day-ahead based on their energy offers for the next day. The DA-GCG program shared many of the features of the RT-GCG program, including after-the-fact submissions of start-up costs. The DA-GCG program was discontinued in October 2011 when it was replaced by EDAC.

c. The IESO introduced EDAC in October 2011.[92] Unlike the RT-GCG program, EDAC does not allow for after-the-fact cost submissions; the IESO uses three-part offers (start-up, speed-no-load, and incremental energy costs) submitted day-ahead by market participants to optimize the energy and operating reserve markets for the next 24-hour dispatch day. The guarantee under EDAC covers costs for the generator's full day-ahead schedule (as opposed to the DA-GCG and the RT-GCG programs, where costs were/are guaranteed only up to the generation facility's MLP and for the duration of its MGBRT). The generator will receive a payment under the EDAC program to the extent that the market revenues earned from production are less than the generator's offered costs over its day-ahead guaranteed schedule. Participation in EDAC is mandatory, although as discussed below generators can avoid getting a day-ahead commitment by submitting uneconomic day-ahead offers.

One of the anticipated outcomes from the introduction of EDAC was a reduction in the overall costs of committing non-quick start generators. According to the IESO, there are two features

[92] See Market Manual 9, "Day-Ahead Commitment Process" at http://www.ieso.ca/imoweb/pubs/dacp/MM9-dacp-manual.pdf. Rules relating to the EDAC generation cost guarantee program are set out in sections 2.2C, 5.8 and 6.3B of Chapter 7 of the market rules and in section 4.7D of Chapter 9 of the market rules. Under the market rules, the guarantee under EDAC is referred to as a "production cost guarantee".

of EDAC that were expected to lead to that result.[93] First, 24-hour optimization and the ability to schedule generators up to their maximum capacity (as opposed to MLP under the DA-GCG) suggested that fewer units should need to be committed under a generation cost guarantee program to meet a given level of demand. Since starting up a generator can be costly, fewer commitments (and, hence, fewer start-ups and fewer costs) should yield lower overall costs. Second, the IESO anticipated that generators could negotiate more favourable gas or other fuel rates when they have a day-ahead guarantee that extends over their full schedule. Competitive forces would cause these lower fuel prices to be reflected in lower offer prices, which in turn would lower the costs of committing these units.

The Panel undertook an analysis of the IESO's generation cost guarantee programs, with a view to ascertaining the extent to which anticipated cost savings have materialized with the introduction of EDAC. That analysis, described in section 3.2.3, reveals that the overall cost of committing gas-fired units (expressed as $ per MWh of guaranteed output), after adjusting for inflation and changes in fuel prices, has increased by 3.5% following the replacement of the DA-GCG program with EDAC.

In section 3.2.4, the Panel considers some of the reasons why the inflation-adjusted commitment costs have not declined with the introduction of EDAC. While the Panel believes that EDAC is an improvement over the original day-ahead commitment process, the continued operation of the RT-GCG program in its present form and in parallel with EDAC weakens the incentive for generators to make competitive offers for a guaranteed schedule in EDAC. A generator that is not cost-competitive in EDAC can still receive a guarantee under the RT-GCG program, which has a lower hurdle for obtaining a guaranteed schedule (because start-up costs are submitted after the fact, and are therefore not considered by the IESO at the time a commitment is made) and which also has a guarantee that sometimes may be more attractive than an EDAC guarantee. In addition, the fact that very few exports participate in EDAC creates opportunities for generators without a day-ahead commitment to receive a guarantee under the RT-GCG program.

[93] See the IESO's report titled "Day-ahead Market Evolution Preliminary Assessment" available at: http://www.ieso.ca/imoweb/pubs/consult/se21/se21-20080505_DAM_Assessment_Report.pdf

3.2.2 *EDAC Compared to Other Guarantee Programs*

Table 3-4 summarizes the key features of the RT-GCG, DA-GCG and EDAC programs.

Table 3-4: Generation Cost Guarantee Programs

	Real-Time RT-GCG	**Day-Ahead DA-GCG**	**Day-Ahead EDAC**
Effective Dates	2003 to **Present** (Last modified in 2009)	2009 to October 2011 (Replaced with EDAC)	October 2011 to **Present**
Eligible Generators	Non-quick start resources can receive guarantee payments	Same as RT-GCG	All generation resources must participate in EDAC, but only non-quick start resources can receive guarantee payments
Participation	Voluntary	Same as RT-GCG	Mandatory
Scheduling Requirements for Obtaining a Guarantee	Scheduled in pre-dispatch to at least MLP for half of the generator's MGBRT hours	Scheduled day-ahead to at least MLP for the generator's full MGBRT	Same as DA-GCG
Generator's Costs Covered by the Guarantee	Start-up costs and incremental energy costs for MLP for the duration of MGBRT	Same as RT-GCG	Start-up costs, speed-no-load costs and incremental energy costs for the full day-ahead schedule (which may be above MLP and extend beyond MGBRT)
Cost Submissions Relative to the Granting of the Guarantee	Incremental energy costs submitted before the guarantee is granted, start-up costs submitted after	Same as RT-GCG	All costs submitted before the guarantee is granted
Revenue Used to Offset Generator's Costs Covered by the Guarantee	Revenues for MLP for the duration of start-up and MGBRT (minimum run-time)	Same as RT-GCG	Revenues for the full day-ahead schedule (which may be above MLP and extend beyond MGBRT)

EDAC was intended to address the shortcomings of the DA-GCG program. One of the changes introduced with EDAC was to make participation mandatory. All generators are required to submit three-part day-ahead offers. Under the DA-GCG program, if a generator's offer was economic and it received a commitment for the next day, it could reject the commitment in favour of either participating in the RT-GCG program or operating in real-time without a guarantee. EDAC removed that possibility; a generator that receives a commitment in EDAC is held to that level of production and cannot decline the commitment. [94]

Intuitively, making participation in EDAC mandatory should increase the level of commitments made under EDAC, and that has been the case. Table 3.5 shows the total level of commitments made under the day-ahead (DA-GCG or EDAC, as applicable) and RT-GCG programs for both natural gas- and coal-fired generators in the year before and the year after the introduction of EDAC. The level of commitments made day-ahead increased from 5.7 TWh in the year before EDAC was introduced to 8.3 TWh in the year after introduction. The total in each year is a fraction of the total market demand, as generators that are not eligible to participate in the generation cost guarantee programs also produce electricity to meet total demand.

Table 3-5: Committed Generation under the Day-Ahead and Real-Time Programs Before and After Introduction of EDAC (TWh)

Timeframe	Generation due to Day-Ahead Commitments	Generation due to Real-Time Commitments	Total Commitments
Pre-EDAC (Oct 13, 2010- Oct 12, 2011)	5.7	9.9	15.6
Post-EDAC (Oct 13, 2011 – Oct 12, 2012)	8.3	8.3	16.7

Although commitments made day-ahead increased substantially, this was not matched by a comparable decrease in commitments made under the RT-GCG program. One of the reasons that commitments under the RT-GCG program continue to be substantial appears to be that exporters have not fully participated in EDAC.

Importers have an incentive to participate in EDAC and to submit day-ahead offers – the IESO guarantees part of the revenue they will earn the next day through an intertie offer guarantee. Exporters, however, have no such incentive, and can in some cases be forced to pay a withdrawal

[94] More specifically, if a generator does not produce energy that was guaranteed day-ahead (and if it is dispatched to its full schedule in real-time), it is subject to a failure charge.

charge if they are scheduled day-ahead and fail to honour their commitments. Thus, very few exporters have participated in EDAC. The end result is that the IESO commits day-ahead generation and imports to meet a forecasted level of demand that excludes most exports. When additional exports appear the next day in real-time, those generators that were not scheduled day-ahead will often be committed under the RT-GCG program to produce energy to satisfy export demand.

Another major change introduced by EDAC is that all costs, including start-up costs, are submitted day-ahead and are therefore considered by the IESO when it decides which generators should be committed for the next day. Under the DA-GCG program (and the same remains true under the RT-GCG program), start-up costs were submitted after-the-fact and where therefore not considered by the IESO when deciding which generators should be scheduled. As a result, dispatch decisions were made based only on offered incremental energy costs, creating the potential for uneconomic dispatch. Specifically, the IESO could instruct a generator to start up – and to incur start-up costs that would be guaranteed by the IESO – because its offer price was the next cheapest offer in the supply stack even though it might be more economic to ask another, seemingly more expensive, generator that was already online to increase its output.

A further key difference between EDAC and the DA-GCG program is the costs that are subject to a guarantee and the market revenues that are used to offset those costs in calculating the amount of the guarantee payment. Under the DA-GCG program, only costs related to production up to a generation facility's MLP (and only to the end of its MGBRT) were subject to a guarantee, and the offsetting revenues were limited to the same production. None of the revenues earned by the generator as a result of operating at a level above its MLP (and/or beyond its MGBRT) during a guaranteed run were considered by the IESO in determining the amount of any guarantee payment. The RT-GCG program is the same. Under EDAC, however, the IESO can schedule, and guarantee the costs of, generators up to their maximum offered output, and all of the market revenues earned by a generator during a run guaranteed under EDAC are counted by the IESO when it determines whether a guarantee payment needs to be made to the generator (and, if so, the amount of that payment).

3.2.3 *Analysis of Costs under the Generation Guarantee Programs*

This section describes the analysis that was conducted by the Market Assessment Unit (MAU) to compare unit commitment costs in the year before and the year after the introduction of EDAC. The analysis is limited to gas-fired generators that participated in the IESO's guarantee programs.[95] Further detail about the study is presented in Appendix 3-A.

3.2.3.1 Calculation of Average Offered Costs

To calculate the average cost for production over each run guaranteed under the RT-GCG and DA-GCG programs, each generator's offered incremental energy cost was multiplied by its injections into the grid. This represents the amount required by the generator to cover the cost of fuel for energy production. Start-up fuel costs and the start-up operation, maintenance, and administration (OM&A) costs, both of which are submitted after-the-fact, were also included as they are covered by the RT-GCG and DA-GCG programs.

To eliminate the impact of changes in the prices of natural gas and other inputs over the two-year period, the generators' offers were normalized for changes in gas prices at the Dawn Hub, and OM&A costs were adjusted for changes in the Canadian GDP Implicit Price Index (a broad measure of inflation). Because the level of demand was very similar from one period to the next, no adjustment was made for changes in demand when calculating the average.[96]

A generator may choose not to submit start-up costs after-the-fact when it has earned enough revenue in the market to cover its start-up costs, because submitting these costs under the RT-GCG program (or the DA-GCG program) will not provide any additional payments. When start-up costs were not submitted by a generator after a RT-GCG or DA-GCG run, it was assumed that the start-up cost incurred by the generator would have been equal to the average submitted start-

[95] Although all generation resources must submit offers under EDAC, only some generation facilities are eligible for the guarantee programs. Eligible generators include more than just gas-fired generation facilities. However, comparing the average costs in each period for other eligible generators is misleading given a change in offer behaviour by some of these other resources as well as the impact of Automatic Generation Control contracts. This issue is discussed further in Appendix 3-B.
[96] Data on the level of demand in each period, as well as the level of wind production and net exports, is presented in Appendix 3-C.

up cost for other runs. That amount was included in the total costs for the run to ensure that all costs were included in the calculation.[97]

To calculate the average cost for production during a run guaranteed under EDAC, the offered incremental energy cost (multiplied by each generator's energy injections over the run), the speed no-load cost, and the start-up costs were used. As noted above, under EDAC these three costs are offered in advance as part of the generator's day-ahead offer; there are no after-the-fact cost submissions under EDAC. The three costs were adjusted for inflation and changes in fuel costs, in the same way as for costs under the RT-GCG and DA-GCG programs. An additional cost component included in the EDAC analysis is linked to unused energy (energy that, while scheduled in EDAC, is not needed in real-time; that energy is covered by the guarantee provided that the generator lowers its day-ahead offer moving in to real-time).[98]

The calculated average represents the as-offered cost per MWh that generators sought for their output. The average offered cost represents the revenue required by the generator to cover its costs as those costs were submitted to the IESO (those submitted costs may or may not reflect the generator's actual costs). A generator may cover its offered costs through market revenue (when it operates profitably) or a combination of market revenue and guarantee payments.

3.2.3.2 Changes in Average Offered Cost

Table 3.6 shows the average offered cost for gas-fired generation units pre- and post-EDAC. The average offered cost for these gas-fired units in the year after EDAC was introduced, after accounting for changes in fuel costs and inflation, increased by 3.5% compared to the average offered cost in the prior year.

---

[97] Various checks were completed to ensure that the absence of an after-the-fact start-up cost submission was in fact due to the generator's run being profitable, and not for other reasons (such as, for example, because the generator tripped offline briefly but returned to complete an earlier run). These checks and other assumptions are listed in detail in Appendix 3-A.

[98] If a generator produces less output than was committed day-ahead, and it also lowers its day-ahead offer (to increase its chance of being dispatched to its full day-ahead schedule), the IESO will pay that generator for the difference between its day-ahead offer and its revised offer for the unused energy—energy that was guaranteed in advance but was not needed during real-time operations. This payment gives generators committed day-ahead an incentive to lower their offers, which increases the likelihood that the IESO will dispatch them to their full day-ahead schedule. While this payment may offset any costs incurred from storing or rescheduling gas that a generator has procured in anticipation of production, it represents a portion of guaranteed costs, not offered costs. Note that any payouts imply that even though the generator had lowered its offer, the output that was committed the day before is uneconomic (perhaps due to an unanticipated reduction in demand, or an increase in low cost supply). Failing to include this payment in the calculations would mean omitting a portion of the costs that are guaranteed by the IESO. This would underestimate the total costs of committing generation day-ahead and lower the average cost of commitment. These payments were not adjusted for inflation.

Table 3-6: Average Offered Cost for Gas-fired Generation under Day-Ahead and Real-Time Cost Guarantee Programs
($/MWh)

Timeframe	Average Offered Cost
Pre-EDAC (Oct 13, 2010-Oct 12, 2011)	$35.45
Post-EDAC (Oct 13, 2011-Oct 12 2012)	$36.69

The average offered cost in the post-EDAC time frame in Table 3.6 represents the average offered cost under both the RT-GCG and EDAC guarantee programs. The average offered costs under each program post-EDAC are shown separately in Table 3.7. This table shows that the EDAC average offered cost is slightly lower than the RT-GCG average offered cost post-EDAC; however, both of these costs are above the pre-EDAC average offered cost of $35.45.[99]

Table 3-7: Average Offered Cost for Gas-fired Generation under Day-Ahead and Real-Time Cost Guarantee Programs
(adjusted for changes in fuel cost and inflation)
($/MWh)

Time Frame	Program	Average Offered Cost
Post-EDAC (Oct 13, 2011- Oct 12 2012)	EDAC	$35.89
	RT-GCG	$37.22

The changes introduced through EDAC should put downward pressure on the average cost of output committed under the program. Because more energy has been subject to a day-ahead commitment since the introduction of EDAC, a higher average cost for commitments post-

[99] Because of the similar nature of the DA-GCG and RT-GCG programs pre-EDAC, the average offered cost under each of the programs pre-EDAC is not presented separately.

EDAC does not necessarily mean that EDAC has not been scheduling resources more efficiently. Higher commitments made day-ahead have two effects: committing more energy from each generator will tend to reduce the average cost (economies of scale effect), but committing more energy may also require committing higher cost resources (upward sloping supply curve effect).

If the upward sloping supply curve effect outweighs the economies of scale effect, then the commitment of higher cost resources would raise the average cost for energy committed under EDAC. To determine whether this is the case, we turn to the average cost from individual generators.

3.2.3.3 Average Offered Costs of Individual Generators

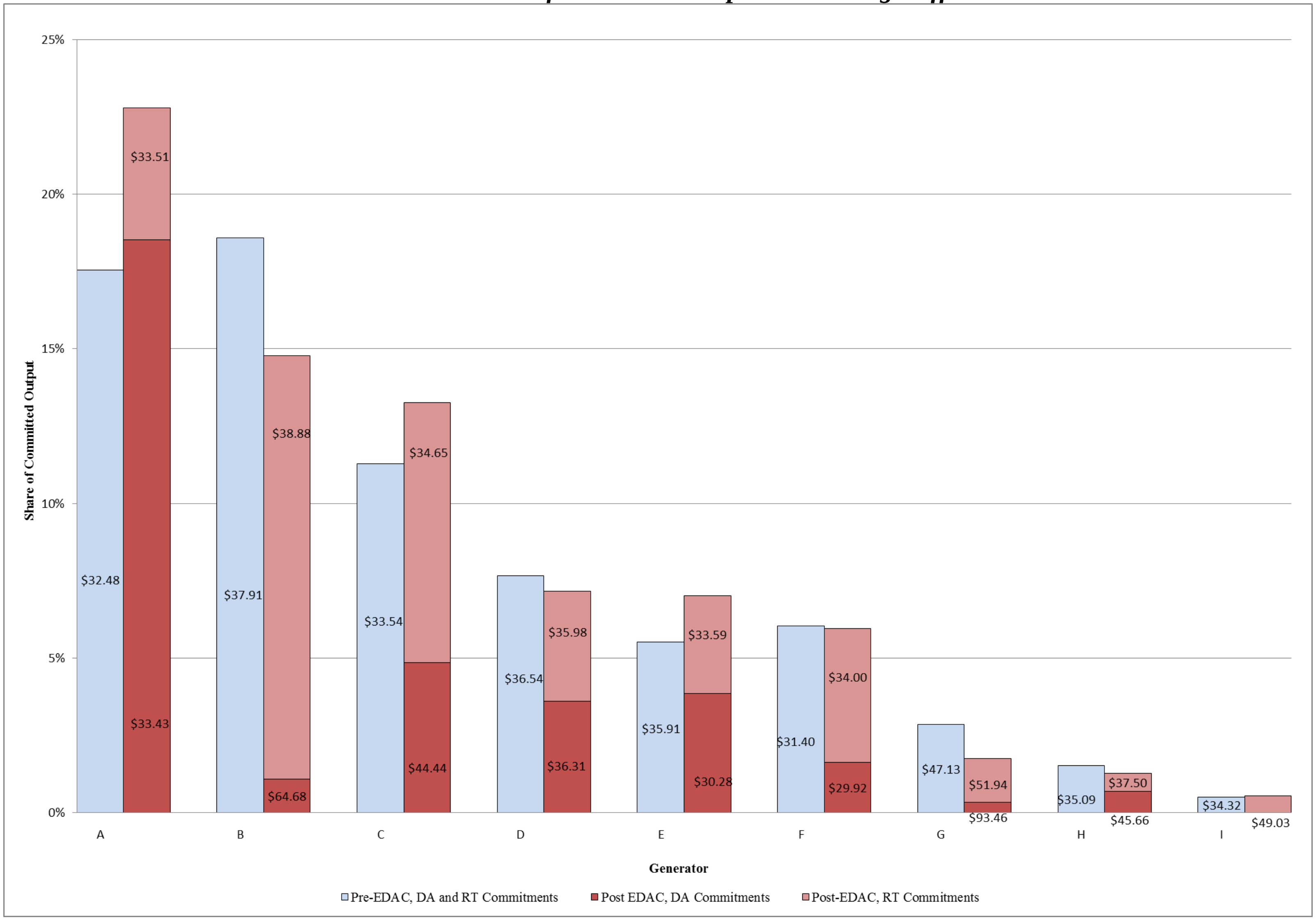
Figure 3.12 shows each eligible gas-fired generator's share of commitments under the RT-GCG and the day-ahead programs (DA-GCG or EDAC, as applicable) pre- and post-EDAC. The average cost information for both programs (RT-GCG and DA-GCG) pre-EDAC is combined in the graph because the differences between the two guarantee programs prior to EDAC were not significant. The share of commitments represents each generator's share of the total output produced by eligible generators through a commitment under each program (the shares do not sum to 100% as the graph presents the offered costs of gas-fired generators only, not all eligible generators). The average offered cost was calculated for each generator in the manner described in section 3.2.3.1 above, and is included in the graph as the number overlaying each bar (as above, the costs include both energy costs and start-up costs to in order to capture the full cost of production, which is then divided by each generator's output).

Figure 3.12 shows that each generator's average offered costs differed under the different programs, for some generators quite significantly. In particular:

- Generator A has offered costs that are roughly similar in both the pre- and post-EDAC time frames, and has produced a larger share of committed output post-EDAC.
- Generators B and C have higher average offered costs in the day-ahead portion of their commitments post-EDAC, while their average costs under the RT-GCG post-EDAC are closer to their average offered costs pre-EDAC. Generator B in particular has received few commitments under EDAC. Generators G and H, though smaller units, show a trend

similar to Generators B and C, offering a higher average cost for the day-ahead portion of their commitments compared to their RT-GCG offered cost post-EDAC and their average offered cost post-EDAC. These generators have also received few day-ahead commitments post-EDAC.

Figure 3-12: Individual Gas-Fired Generator Shares of Committed Output and Average Offered Cost Pre-EDAC and Post-EDAC



The fact that some generators have such different average offered costs as between the two post-EDAC programs, and also as compared to their pre-EDAC average offered costs, suggests that generators are making different offers under each program. If a generator fails to get a committed schedule in EDAC, it will likely have a second opportunity to get a guaranteed run under the RT-GCG program. For this reason, some generators may choose to offer at a premium in EDAC. If they receive a commitment it will be at a favourable rate, and if they do not receive a commitment they have a second opportunity to get a commitment under the RT-GCG program.

To the extent that generators are pursuing this strategy, there are adverse consequences for the cost of commitments. The IESO will be forced to choose from among a set of higher cost offers, while at the same time generators that are not committed day-ahead can lower their offers in real-time, receive a guarantee and recover their incremental energy and start-up costs. This is compounded by two important factors:

- The RT-GCG program can give generators more generous guarantee payments compared to commitments made under EDAC. This is because the RT-GCG program counts less of a generator's revenues during a run against its guaranteed costs (incremental energy and start-up) when determining the amount of any guarantee payment. As discussed below, this effect can be heightened for plants with both combustion and steam turbine units, although the heightened effect is likely not material.

- Generators are committed under the RT-GCG program based on their incremental energy offers only, as start-up costs are submitted after-the-fact (but are still covered by the guarantee). This puts less pressure on generators to submit competitive start-up costs under the RT-GCG program than under EDAC.

As noted earlier, higher average offered costs in EDAC could be the result of the higher level of day-ahead commitments made post-EDAC. However, the above observations regarding individual generators' offered costs casts doubt on the validity of that assumption. If it were true that the additional resources committed day-ahead are those with higher costs (an upward sloping supply-curve), we would not expect to see these same resources offering a lower average cost under the RT-GCG program.

If generators offered in the same way under both programs, one would expect EDAC to schedule the lowest cost resources first and move up the supply curve to meet the forecast level of demand. Although EDAC can optimize costs by scheduling units over longer intervals, taking into account the full costs of commitments, the optimization occurs over a different set of offered costs than are subsequently offered in real-time. Because some generators have a higher average offered cost under EDAC than under the RT-GCG program (see Figure 3-12), the cost of commitments under EDAC will be higher than they would be if those generators offered the same (lower) costs under EDAC as they have under the RT-GCG program. This is not caused by anything specific to EDAC itself, but rather is a result of differences between the EDAC and RT-GCG programs. Because of these differences, it is unlikely that EDAC has exhausted the potential benefits that could be achieved from improved scheduling efficiency day-ahead.

3.2.4 *Guarantee Payments under the RT-GCG Program*

As noted above, some generators may prefer the RT-GCG program over EDAC. For example, Figure 3-12 shows that Generator I produced no output under a day-ahead commitment post-EDAC. One reason for such a preference may be that guarantee payments under the RT-GCG program can be more generous because less of a generator's market revenues over the guaranteed run are counted against the guaranteed costs (incremental energy and start-up) under the RT-GCG program than is the case under EDAC. Differences in the way in which some combined cycle facilities are settled under the EDAC and RT-GCG programs can also contribute to more generous payments under the RT-GCG program (but see below regarding the likely immaterial nature of the difference).

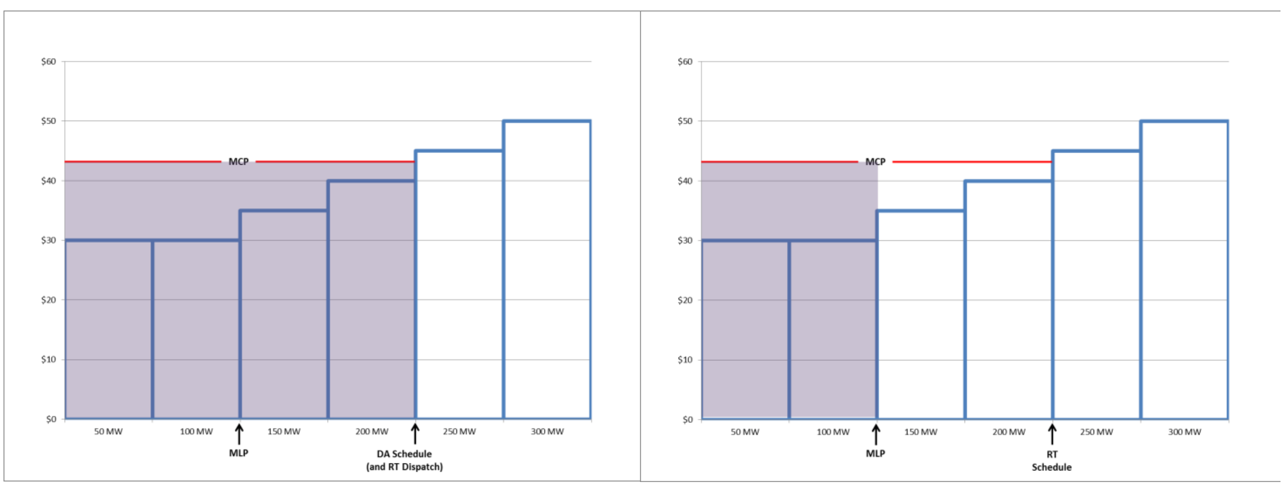
Under the RT-GCG program, the revenues that are counted against the guaranteed costs are limited to the generation facility's MLP output and to the end of the facility's MGBRT rather than being based on total actual output. As such, none of the market revenues earned by the generator as a result of operating above the facility's MLP (and/or for longer than the facility's MGBRT) are considered by the IESO in determining the amount of any guarantee payment. In contrast, under EDAC the IESO considers the revenues on the total (day-ahead) scheduled production (even if higher than the facility's MLP and/or extending beyond the facility's MGBRT) when determining the amount of any guarantee payment.

3.2.4.1 Revenues under RT-GCG Limited to MLP

Figure 3-13 illustrates the difference in the market revenues that are counted against the guaranteed costs under each of EDAC and the RT-GCG programs in relation to a generation facility's level of output. The figure assumes that the generator offered its output day-ahead under EDAC starting at $30/MW for the first 100 MW and increasing $5 for each additional 50 MW block of output. If the generator receives a day-ahead schedule for 200 MW, the market revenues that it earns on all of its guaranteed output (200 MW) will be counted against its guaranteed costs. The guarantee will then be paid only if, and to the extent that, the revenues are insufficient to cover those costs.

If the same generator were to start under the RT-GCG program, however, only revenues earned on output up to the facility's MLP (assumed to be 100 MW) will be counted against its guaranteed costs. While the unit may earn revenues over the entire 200MW of its output, only the revenues earned on production up to MLP will be taken into account in calculating the amount of the guarantee. This could lead to situations where a generator earns sufficient revenues over its total run to cover its guaranteed costs, but still receives a guarantee payment.

Figure 3-13: Revenue over output Considered under EDAC and RT-GCG Programs over a Generator's Run



EDAC guarantees all scheduled output and counts revenues on all production against guaranteed costs

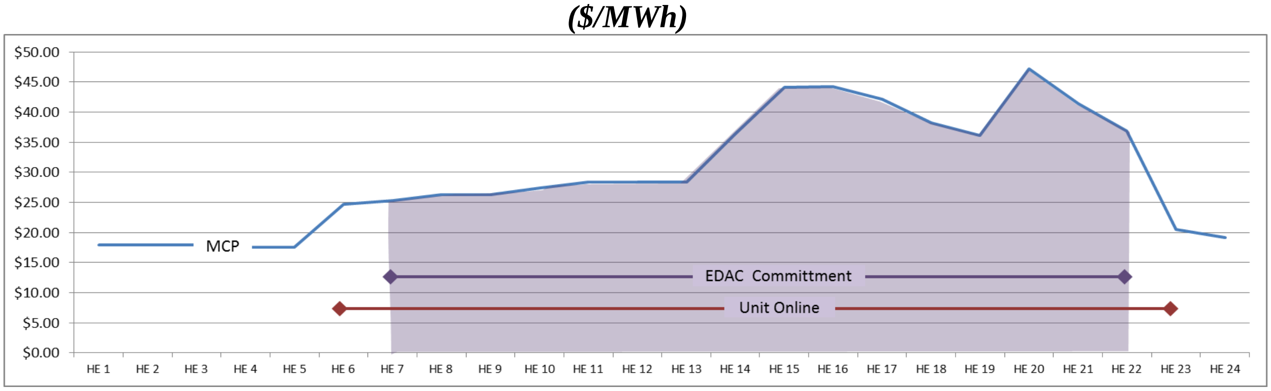
RT-GCG guarantees up to MLP and does not count revenues for production above MLP against guaranteed costs

3.2.4.2 Revenues under RT-GCG Limited to MGBRT

Commitments made under EDAC provide a generator with a guarantee for all of the hours covered by its day-ahead schedule, and revenues earned over all of those hours are considered by the IESO when determining the amount of any guarantee payment. In contrast, under the RT-GCG program only revenues earned during the generator's minimum run-time (start up to end of MGBRT) are considered by the IESO in determining the amount of the guarantee. If the generator does not earn sufficient revenues over its minimum run-time (and up to MLP) to cover its guaranteed costs, it will receive a guarantee payment under the RT-GCG program. If the generator operates above its MLP and/or continues its run beyond its MGBRT, the generator will nonetheless receive the guarantee payment even if its revenues over the total run exceed its guaranteed costs.

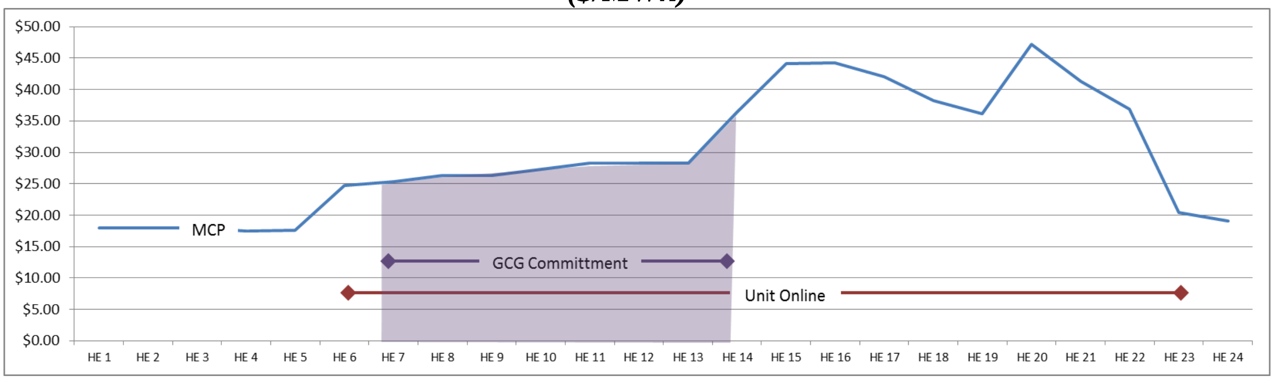
By way of example, suppose a generator receives a commitment in EDAC between hours ending (HE) 7 and 22. If the generator offered its output at \$25/MW, then the generator earns a profit when the MCP exceeds \$25/MWh. If the unit is committed under EDAC for the sixteen hours, then the revenues earned over those sixteen hours will be counted against the generator's guaranteed costs in determining the amount of the guarantee payment. The revenue counted against the guaranteed costs under EDAC is illustrated in the shaded area in Figure 3-14.

Figure 3-14: Revenue Per MW Considered under EDAC over Generator's Run ($/MWh)



Under the RT-GCG program, the same generator committed to start at the same time will have the only the revenues that it earns over its minimum run-time counted against its guaranteed costs. If the unit is committed in HE 7, and has a MGBRT of 8 hours, it will be committed until HE 14. If its offers are still economic post-HE 14, it may continue the run and earn additional revenues, but only the revenues earned to the end of its MGBRT will be counted against its guaranteed costs when determining the amount of the guarantee payment. This is illustrated in the shaded area in Figure 3-15.

Figure* 3-15: *Revenue* C*onsidered under* EDAC *over Generator's* Run *($/MWh)



Because the RT-GCG program limits the revenue that is taken into account when making the guarantee payment calculation, it leads to more frequent and larger guarantee payments. This provides an incentive to participate in the RT- GCG program in preference to EDAC. Any resulting reduction in participation in EDAC tends to put upward pressure on the costs at which generators are committed under EDAC.

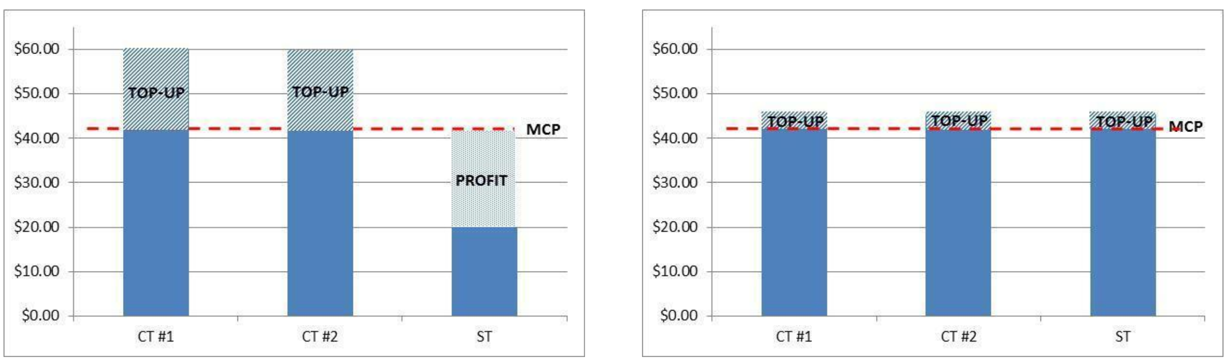
3.2.4.3 Pseudo-Unit Modelling for Combined Cycle Plants

Combined cycle plants have both combustion turbine and steam turbine units. Some generators have arrangements such that each unit can be scheduled separately, with separate offers and cost submissions. However, these units must nonetheless operate in a fixed sequence: a combustion turbine must start before the steam turbine can start, and as more combustion units start the minimum output of the steam turbine increases.

This can create complications for a guarantee program, because a combustion turbine may have large start-up costs while a steam turbine may have low start-up costs, and each may offer their energy output at different prices. However, the steam turbine can only operate when at least one of the combustion turbines is also operating.

The impact on guarantee payments under the RT-GCG program is illustrated in the left hand panel of Figure 3-16. The example in the figure assumes that the average offered cost of a generator is $60/MW for the combustion turbine and $20/MW for the steam turbine. If the average MCP over the generator's guaranteed run is $43/MWh, it will not receive sufficient revenue to fully cover its guaranteed costs for the combustion turbine, and so it will receive a guarantee (top up) payment for the combustion turbine units. However, the generator will earn revenues for every MW of output from the steam turbine. Because the steam turbine is treated as a separate unit, these revenues (less incremental operating costs) are not considered by the IESO when calculating the amount of the guarantee payment for the combustion turbine units, as shown in Figure 3-16.

Figure 3-16: Guarantee Payments for Combined Cycle Plants under Generation Cost Guarantee Programs
($/MWh)



RT-GCG **EDAC (Pseudo Unit Modeling)**

When EDAC was introduced, the IESO began to use "pseudo-unit modeling". With pseudo-unit modeling, the combustion turbine and a portion of the steam turbine are scheduled together, and their costs are aggregated in a manner that reflects their respective operating characteristics. When the guarantee payment is calculated, a proportion of the steam turbine's output is associated with each combustion turbine (creating "pseudo-units" for settlement purposes) and the revenues earned by each pseudo-unit are counted against the pseudo-unit's guaranteed costs in determining the amount of any guarantee payment. Overall, this results in lower guarantee payments than under the RT-GCG program, as shown in the right hand panel of Figure 3-16 above. Specifically, under EDAC each of the pseudo-units in the example will receive a guarantee (top-up) payment of $2.44/MWh, considerably less than the guarantee payable to the same generator under the RT-GCG program.

As noted below, however, it appears based on an IESO analysis that the savings that could be achieved by introducing pseudo-unit modeling to the RT-GCG program are not likely to be material.

3.2.5 *Conclusions and Recommendations*

EDAC represents an improvement over the original day-ahead commitment process. However, based on the analysis set out above the Panel believes that EDAC has been unable to fully deliver the anticipated reductions in commitment costs, and this largely because of the continued co-existence of the RT-GCG program and the differences that exist between the two programs.

The Panel has previously recommended that the IESO re-examine whether the RT-GCG program continues to provide a net benefit to the Ontario market following implementation of EDAC.[100]

The Panel acknowledges that some re-examination of the RT-GCG program has taken place in the context of the IESO's stakeholder engagement pertaining to the review of the IESO's generation cost guarantee programs (referred to as "SE-111"). However, based on materials from SE-111, it would not appear that the IESO has conducted a detailed analysis that demonstrates a continued need for the RT-GCG program in light of changes that have occurred in the market since that program was introduced, including the increasing number of generation facilities that operate under contracts with the Ontario Power Authority or whose payment amounts are set by the Ontario Energy Board and the implementation of EDAC, among other potentially relevant developments.

[100] See the Panel's February 2011 Monitoring Report, p. 96, available at: http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20110310.pdf

Recommendation 3-1

The Panel recommends that the IESO provide a detailed analysis to confirm whether the real-time generation cost guarantee (RT-GCG) program continues to be needed in light of the implementation of the enhanced day-ahead commitment process (EDAC), of changes in Ontario's generation capacity, and of other changes in the market since the RT-GCG program was introduced.

Based on the Panel's analysis above, the Panel believes that generators have an incentive to participate in the RT-GCG program in preference to EDAC. In the Panel's view, this incentive – which results from differences in the revenues that are used to offset guaranteed costs when determining the amount of a guarantee payment as between the two programs – may be hindering EDAC in its ability to fully deliver on reduced commitment costs. The Panel therefore believes that, if the RT-GCG program is retained, the revenue offsets should be harmonized as between the two programs. While the Panel has noted the benefits of pseudo-unit modeling under EDAC, based on an analysis conducted by the IESO in the context of SE-111 the savings attainable from moving to pseudo-unit style settlements for the RT-GCG program are not likely to be material.[101] The Panel is therefore not recommending that the IESO introduce pseudo-unit modeling in the RT-GCG program.

Recommendation 3-2

If the IESO, after performing its detailed analysis, determines that the RT-GCG program continues to be needed, the Panel recommends that the IESO modify the RT-GCG program such that the revenues that are used to offset guaranteed costs under the program are expanded to include any profit (revenues less incremental operating costs) earned (a) on output above a generation facility's minimum loading point during its minimum generation block run time (MGBRT), and (b) on output generated after the end of the facility's MGBRT.

The Panel has also noted that the absence of significant export participation in EDAC creates a further opportunity for generators without a day-ahead commitment to receive a guarantee in real-time. This may be contributing to higher levels of commitments under the RT-GCG program

[101] See slides 13-16 in the IESO's SE-111 November presentation, available at: http://www.ieso.ca/imoweb/pubs/consult/se111/se111-20131107-Presentation_Revised.pdf .

post-EDAC. In 2008, the IESO considered the issue of incentives to encourage exports to participate in EDAC, recognizing that this could lead to improved efficiency through better day-ahead commitment and that efficiency gains would be realized through reduced overall commitment costs that otherwise would not have been achieved. The IESO explored seven options, and concluded that the incentives would be difficult to structure and would likely not provide significant benefits in terms of reducing overall commitment costs under EDAC.[102] However, in the Panel's view the benefits of including export demand day-ahead extend beyond EDAC because doing so is likely to reduce the need to commit additional resources in real-time. Accounting for export demand day-ahead would ensure that more generation is subject to 24 hour optimization and would help to strengthen competition among generators for a day-ahead commitment in EDAC.

<u>Recommendation 3-3</u>

The Panel recommends that the IESO re-examine the question of integrating exports into EDAC to reduce the need to commit additional generation in real-time to meet export demand that currently only appears in the market in real-time. While the Panel is not recommending a specific approach for integrating exports, the following have been identified as potential options:

a) introduce a mechanism that encourages exports to bid in EDAC; or
b) include a forecast of exports when commitments are made under EDAC.

[102] A summary is available in the IESO's report "EDAC-Options for Export Incentives", October 29, 2008, available at: http://www.ieso.ca/imoweb/pubs/consult/se21-dagei/se21-20081106-Export_Discussion.pdf .

Ontario Energy Board Commission de l'énergie de l'Ontario

Ontario

Market Surveillance Panel

Congestion Payments in Ontario's Wholesale Electricity Market: An Argument for Market Reform

December 2016

Executive Summary

Since market opening, no element of Ontario's wholesale electricity markets has attracted the attention and concern of the Market Surveillance Panel (Panel) more than Congestion Management Settlement Credit (CMSC) payments. These payments, a fundamental adjunct of Ontario's uniform price/two schedule market design, have resulted in inefficiencies and inappropriate wealth transfers, and have shown themselves to be susceptible to gaming.

This report provides a retrospective of Ontario's history with CMSC payments. It notes issues that have arisen over the years, and actions that the Independent Electricity System Operator (IESO) has taken to address a number of the Panel's concerns in whole or in part. Although little in this report is new, the Panel believes that publication of its report at this time is opportune, given the IESO's recent decision to embark on a broad Market Renewal initiative that holds promise in terms of a re-design of the market.

The Panel supports the replacement of the uniform price/two schedule market design with a design that would facilitate future market renewal and rely less on out-of-market payments like CMSC payments. In particular, the Panel believes that some form of locational pricing should be introduced, whether for market participants only or for residential and other smaller volume consumers as well. This report uses CMSC payments as a case study to illustrate and reinforce the need for – and importance of – fundamental market reform.

IESO Annual Update to the Ontario Energy Board on Actions Taken to Address Market Surveillance Panel Recommendations

(Period from January 2020 – December 2024)

IESO Licence Obligation under Section 6.2.5

Provide the Ontario Energy Board (OEB), on or before the end of each calendar year, with the status of actions taken by the Licensee further to all recommendations addressed to the Licensee in any report issued by the Market Surveillance Panel (MSP) in that year and the preceding four calendar years to the extent that they remain outstanding and, where no action has been taken in relation to a recommendation, the rationale for not taking action. The Licensee's response to recommendations in any report issued by the MSP within 30 days of the end of the calendar year will be included in the succeeding report.

Report	Recommendation Number	Recommendation	IESO 2024 Update to the OEB
July 16, 2020	3-2	In order to provide more consistent market outcomes, the IESO should give further consideration to improving how the need for additional system flexibility is addressed, such as specifying the conditions that require intervention and scheduling the required amount of spinning reserve explicitly in the normal Operative Reserve (OR) market. Although it is acknowledged that no industry standard exists to address flexibility, alternative solutions should also	The IESO completed a review of the conditions under which the flex reserve can be increased or decreased to a maximum or minimum input value that differs from the current single value. The new upper and lower amounts of Operating Reserve (OR) proposed, are in the final approval process. Following approvals, the required process changes will be implemented.

ieso Connecting Today. Powering Tomorrow.

Report	Recommendation Number	Recommendation	IESO 2024 Update to the OEB
		be considered to ensure the most suitable approach is used.	
December 10, 2020	2-1	The IESO should eliminate the payment for start-up costs for second and subsequent Real-Time Generation Cost Guarantee (RT-GCG) runs in a day. Alternatively, when a generation unit has participated in the RT-GCG program once during a day, the IESO should consider ways to have the generation unit compensated on the basis of the lesser of the second and subsequent submitted start-up costs or the estimated cost of keeping the generation unit online between RT-GCG runs.	The IESO agrees that two-shifting generation facilities could be inefficient in certain circumstances. However, eliminating all second start guarantees could deter efficient starts from coming to market. Multi-hour optimization of three-part offers is necessary to verify the efficiency of second starts. As part of the Market Renewal Program (MRP), the IESO will be introducing multi-hour optimization of three-part offers (energy, start up, and speed-no-load) across the day-ahead, pre-dispatch, and real-time timeframes. Multi-hour optimization of three-part offers will only schedule generation facilities for two starts in the same day when it is economically efficient to do so. The IESO does not intend to take any additional actions to change the current Real-Time Generation Cost Guarantee (RT-GCG) program design in advance of MRP. The IESO will continue to conduct audits associated with the RT-GCG program.
December 10, 2020	2-2	The IESO should conduct an audit of RT-GCG cost submissions in situations when a	The IESO routinely audits the RT-GCG program and has been carrying out such audits since

Report	Recommendation Number	Recommendation	IESO 2024 Update to the OEB
		generation unit has a second RT-GCG run within three hours of its first RT-GCG run and the submitted costs of the second run are equal to or higher than the submitted costs of the first run.	2011. Consistent with the MSP's recommendation, the IESO's audits consider submitted costs and the circumstances of each RT-GCG start, including when a generation facility has a second start within three hours of its first start.
December 10, 2020	2-3	The IESO should treat Simultaneous Activation Reserve (SAR) activations in much the same way as it treats emergency imports; namely, by adding demand back in to the unconstrained schedule.	The current approach to pricing Simultaneous Activation Reserve (SAR) imports has been included in the MRP detailed design (see section 3.8.9.2 of the Grid and Market Operations Integration Detailed Design for further information) and stakeholders were given the opportunity to provide input on this approach. In addition, the IESO has assessed the materiality of SAR imports to be low both in terms of frequency of activation and impact on the Hourly Ontario Energy Price (HOEP). With SAR event pricing recently addressed through MRP and the materiality assessed as low, the IESO does not intend to pursue this recommendation any further at this time.
December 10, 2020	3-1	The IESO should produce a report that probabilistically assesses the level of economic (i.e. non-firm) imports that would be appropriate to assume in their various resource adequacy studies for each year in	Through the Reliability Standards Review stakeholder engagement, the IESO reviewed assumptions related to compliance with Northeast Power Coordinating Council (NPCC) resource adequacy standards (NPCC "Directory

Report	Recommendation Number	Recommendation	IESO 2024 Update to the OEB
		the planning timeframe, with stakeholder input, using the Northeast Power Coordinating Council Review of Interconnection Assistance Reliability Benefits study as a reference.	1”), including assumptions for non-firm imports. Through this engagement, the IESO proposed a methodology to determine an appropriate assumption for non-firm imports which takes into account the NPCC Review of Interconnection Assistance Reliability Benefits study. The Reliability Standards Review concluded on April 9, 2021. The stakeholdered methodology to determine an appropriate assumption for non-firm imports was included in the assessments for the 2021 Annual Planning Outlook (APO). The methodology is now included in the IESO’s annual process.
December 10, 2020	3-2	The IESO should better align the assumptions used in planning documents on an ongoing basis or explain in detail the reason for remaining differences, with quantities. This should address, at a minimum, differences in economic import assumptions and different weather scenarios that lead to different capacity need outcomes.	The IESO agrees with the MSP on the need to align assumptions used in planning documents. As stated in previous updates, assumptions for the Reliability Outlook (RO) and Annual Planning Outlook (APO) forecasts were included in the planning documents. Differences in assumptions across these reports have been quantified in the associated methodology documents. There is general alignment in terms of weather assumptions, embedded variable generation, and historical data sets used. The RO has been updated to, among other things, adopt the updated weather methodology consistent with what is in the APO.

Report	Recommendation Number	Recommendation	IESO 2024 Update to the OEB
			Continuing alignment between the two forecasts is an objective of the capital Long-Term Demand Forecast Project. IESO teams are finalizing relevant additional assessment updates, and plan to communicate to external stakeholders to ensure their understanding of the changes implemented.
December 10, 2020	3-3	The IESO should examine and report on potential improvements to its communications with stakeholders regarding the process(es) used to assess the need for and procure resources to meet future capacity needs. The IESO should also provide greater clarity regarding the documents used to inform those procurements and how any auction or procurement targets are set. In particular: • the IESO should publish the analysis and methodology for the Reliability Assurance concept, which appears to be the basis for procuring capacity for the Capacity Auction scheduled for the winter of 2020/21; and • the IESO should explain the purpose of the Reliability Outlook, including a clear indication of which sections of that report may be used for outage planning, which	The IESO agrees with the MSP on the need for transparent and clear communications for planning and procurement processes. Through the Resource Adequacy Engagement, the IESO worked with stakeholders to develop a resource adequacy framework that will enable competitive solutions to meet system needs. The IESO's documents clearly outline how system needs are identified, the methods used to translate those needs into procurement targets, and which processes will be used to procure resources. The IESO can confirm that: • The Annual Planning Outlook (APO) assesses system needs and includes a description of the methodologies used to assess system needs. • The Annual Acquisition Report (AAR) translates those needs into procurement targets and serves as the primary source for procurement decisions. The procurement targets outlined in the AAR do not include additional volumes for "Reliability Assurance."

Report	Recommendation Number	Recommendation	IESO 2024 Update to the OEB
		sections (if any) may be used to inform procurements, and which sections have been included for informational purposes only.	The Reliability Outlook is not used to inform procurements targets. While the Reliability Outlook can assist market participants in assessing outage plans, Market Manual 7.3 is the document that governs the outage assessment process. The purpose of the Reliability Outlook is specified within the Reliability Outlook itself and includes: • Advising market participants of the resource and transmission reliability of the Ontario electricity system • Assessing potentially adverse conditions that might be avoided by adjusting or coordinating maintenance plans for generation and transmission equipment • Reporting on initiatives being implemented to improve reliability within this time frame
December 10, 2020	3-4	The IESO should periodically make available clear descriptions of the range of potential resources that may need to be procured, including the volume (MW), timelines, any required characteristics other than capacity (e.g. energy, ramp, etc.) and expected procurement mechanism (e.g. through capacity auctions, and/or alternative mechanisms) as part of its communication of future capacity needs in reports such as the Annual Planning Outlook.	The IESO agrees with the MSP on the need for transparent and clear communications for planning and procurement processes. Through the Resource Adequacy Engagement, the IESO worked with stakeholders to develop a framework that translates system needs to transparent procurement targets. The Annual Planning Outlook (APO) assesses system needs and includes a description of the methodologies used to assess system needs. The Annual Acquisition Report (AAR) translates those needs into procurement targets and serves as the primary source for procurement

Report	Recommendation Number	Recommendation	IESO 2024 Update to the OEB
			decisions. The AAR includes descriptions of resources to be procured, including the volume (MW), timelines, any required characteristics other than capacity, and expected procurement mechanism.
December 10, 2020	3-5	The IESO should signal its confidence in different planning assumptions by publishing the uncertainty values associated with relevant assumptions and elements used to calculate the capacity need, including at a minimum a range of economic imports and a range of possible demand forecasts based on underlying economic drivers.	Through the Reliability Standards Review engagement, the IESO developed a stakeholdered methodology to determine an appropriate assumption for non-firm imports which will be included in each Annual Planning Outlook (APO). To address uncertainties impacting electricity demand, the IESO builds consideration for load forecast uncertainty into the APO. Assumptions are explained in the APO and are supported through accompanying methodology documents and data tables. The IESO expects to continue this practice. Further, through the Resource Adequacy Engagement, stakeholders and the IESO have recognized a need for an acquisition report that clearly states the IESO's procurement need in the form of the Annual Acquisition Report (AAR). The AAR supplements the IESO's efforts to publicly acknowledge uncertainty in planning assumptions by considering the inherent uncertainties within those assumptions as it translates needs into procurement targets.

Report	Recommendation Number	Recommendation	IESO 2024 Update to the OEB
December 10, 2020	3-6	The IESO should examine and report on potential improvements to its stakeholder engagements regarding the methods and assumptions used to develop capacity needs. Specific consideration should be given to a periodic streamlined process to review the case for procuring existing or new resources that involves stakeholders and is overseen by an objective third party.	The IESO has been conducting annual information and engagement sessions on the Annual Planning Outlook, the Annual Acquisition Report and its Resource Acquisition related engagements; with the recently launched External Relations and Indigenous Engagement Frameworks the IESO will inform, educate a broader spectrum of participants supporting greater transparency regarding the methods and assumptions used to develop capacity needs and procurement mechanisms. On third party oversight, following the Electrification and Energy Transition Panel (EETP) report, the Ministry released its vision statement and initiated consultation on its upcoming Integrated Energy Resource Plan. The IESO will continue to engage with the government on third party oversight as its consultation progresses. However, it is the IESO's view that further actions on this aspect of the recommendation rest with government.
September 2, 2021	3-1	The IESO should develop structural solutions for Capacity Auction resource performance failures, with an emphasis on stronger penalties. In general terms, penalties should work together with a Qualified Capacity process to ensure that capacity payments	The IESO agrees with the MSP's recommendation and has stakeholdered a design for a capacity qualification process and an enhanced performance and availability assessment framework for all Capacity Auction resources (including Hourly Demand Response), where past performance would directly impact future qualified capacity and

Report	Recommendation Number	Recommendation	IESO 2024 Update to the OEB
		net of penalties reflect each resource's ability to deliver capacity when dispatched.	participant revenues. The Market Rules to implement this design have been approved. The new design will provide a financial incentive for resources to improve performance, much stronger financial consequences for poor performance during times of system need and ensure capacity payments net of penalties reflect a resource's ability to deliver capacity when dispatched. The capacity qualification process will have two components (1) availability de-rates, and (2) performance adjustment factors. Availability de-rates will come into effect during the qualification for the 2023 Capacity Auction, which is expected to run in Q4 2023. Due to internal assessments and stakeholder feedback, the performance adjustment factors will be calculated based on auction performance in 2023/24 and will apply to qualification in the 2024 Capacity Auction. This will ensure that performance baselines are being assessed with the new enhancements to the performance assessment framework in effect (e.g. tighter dead bands and higher availability charges). Due to the unique Hourly Demand Response participation framework, there is no real-time availability data for the IESO to use to determine an availability de-rate for qualification. For Hourly Demand Response

Report	Recommendation Number	Recommendation	IESO 2024 Update to the OEB
			resources, IESO has proposed to subject the resource to a higher availability performance assessment when on standby. As an alternative the self-scheduled capacity test performance may be used to adjust the obligation and revenues during the obligation period. These proposals are further described in the update to September 2021 recommendation 3-2.
September 2, 2021	3-2	For all Capacity Auction resources, the IESO should adjust penalties and payments such that there are no financial incentives to submit Capacity Auction offers that exceed expected capabilities.	The IESO agrees with the MSP's recommendation and has stakeholdered a design for a capacity qualification process and an enhanced performance and availability assessment framework for all Capacity Auction resources (including Hourly Demand Response - HDR) where past performance will directly impact future qualified capacity and participant revenues. The Market Rules to implement this design have been approved. Enhancements to the performance assessment framework include performance testing to capability (rather than bids), tightening performance dead bands for hourly demand response resources, determining performance adjustment factors to apply in the future capacity qualification of an individual resource and an in-period adjustment of obligations and payments in accordance with the demonstrated capability of HDR resources.

Report	Recommendation Number	Recommendation	IESO 2024 Update to the OEB
			IESO had initially proposed a settlement charge that would incent HDR resources to make their capacity available during times of system need but has since pursued a new approach to determine an alternative to an HDR availability de-rate in qualification based on further engagement with stakeholders. This design enhancement proposes to adjust an HDR resource's obligation and availability payments for the entire obligation period, including a retroactive adjustment, based on actual delivered capacity demonstrated during a capacity test, if the resource does not deliver to at least its cleared Unforced Capacity (UCAP) value. Total availability payments received throughout the obligation period, including payments received prior to the test and performance assessment, would be included in the payment adjustment. This new proposal was developed based on stakeholder feedback that the IESO's previous approach would incent the wrong behaviour and utilized aspects of approaches to assess availability that are used in other jurisdictions that stakeholders suggested the IESO consider. The 2023 Capacity Auction market rules were amended in 2 parts. The first stream was approved and effective July 19, 2023. Stream 2 was approved and effective October 23, 2023.

Report	Recommendation Number	Recommendation	IESO 2024 Update to the OEB
September 2, 2021	3-3	The IESO should immediately cease reimbursements to gas generators of carbon cost payments.	The Real-Time Generation Cost Guarantee (RT-GCG) program ensures that non-quick start generators are available to meet reliability in real-time. The RT-GCG Program is not a full cost-recovery program. The objective of the program is to provide eligible generators recovery of certain incremental fuel, operating, and maintenance costs incurred as a result of starting up and ramping to minimum loading point, to the extent those costs are not recovered through market revenues. Carbon costs are an additional operating cost incurred by generators during the start-up period and the IESO considers recovery of these costs to be consistent with the program's methodology, and appropriately reimbursed. In the future, the Market Renewal Program (MRP) will introduce the enhanced real-time unit commitment process which will facilitate enhanced competition between generators based on their all-in costs, including carbon costs. MRP will be in service by May 2025.
September 2, 2021	3-4	If the IESO insists on reimbursement of carbon cost payments, they should develop a methodology that preserves the incentives of the carbon price. Any reimbursement should amount to a small percentage of the	The Real-Time Generation Cost-Guarantee (RT-GCG) program’s cost recovery methodology is designed to ensure eligible costs which can include carbon costs to be recovered by generators. This methodology takes into

Report	Recommendation Number	Recommendation	IESO 2024 Update to the OEB
		carbon cost payments imposed by the carbon pricing system. Only facilities that have paid an annual carbon cost charge should qualify for the carbon cost reimbursement.	account the heat rate of thermal generators by assessing the fuel consumed and energy produced specific to startup operations. With further carbon costs potentially incurred during the full run of a facility, an incentive to reduce emissions intensity and resulting carbon costs remains. The IESO also notes that based on the current emissions intensity benchmark and the dispatch patterns and efficiency of Ontario's gas fleet, all eligible RT-GCG participants are expected to incur an annual carbon charge. In the future, the Market Renewal Program (MRP) will introduce the Enhanced Real-Time Unit Commitment (ERUC) process which will facilitate enhanced competition between generators based on their all-in costs, including carbon costs. MRP is expected to be in service by May 2025.
September 2, 2021	3-5	If the IESO does reimburse gas generators for carbon cost payments, the total annual reimbursement from the IESO should be made public to improve transparency, beginning with the total reimbursement to gas generators for 2019 that was made in 2021.	The IESO agrees with the MSP's recommendation and has published the total annual reimbursement for carbon costs under the Real-Time Generation Cost Guarantee (RT-GCG) on the IESO's Market Assessment web page.

Report	Recommendation Number	Recommendation	IESO 2024 Update to the OEB
September 2, 2021	3-6	The IESO should issue a Request for Proposals in all possible cases where it intends to secure a resource to meet an identified system need that cannot be addressed by existing competitive mechanisms (e.g. Capacity Auction).	The IESO is committed to prioritizing the use of competitive mechanisms. The 2022 Annual Acquisition Report (AAR), published on April 4, includes the decision-making methodology used to determine solutions to address identified reliability needs. The planned actions and options identified in the 2022 AAR include a variety of competitive processes, including Request for Proposals. The AAR encourages greater competition by specifying design considerations in long-term commitment processes in locations where system needs exist and there are currently limited capable suppliers to address the need. During the mechanism allocation and target setting step of the methodology, the IESO determines which mechanisms from the Resource Adequacy Framework have a high probability of delivering on the needs, taking into consideration whether: (1) there is sufficient time to run a competitive procurement, and (2) a sufficient pool of potential resources or projects exist to support competition. Where competitive mechanisms cannot be implemented, either due to urgency of need or specific requirements that reduce the pool of competition, opportunities such as existing assets, potential import opportunities, or other

Report	Recommendation Number	Recommendation	IESO 2024 Update to the OEB
			means are considered to satisfy the identified needs.
September 2, 2021	3-7	In advance of full implementation of the IESO's Resource Adequacy Framework, when non-competitive procurements may be required, information should be published that clearly states why a non-competitive procurement was necessary, what effort was made to encourage competition, specific details for both the need and the proposed solution (e.g. amount of annual Unforced Capacity and location), and whether additional actions are necessary if the proposed solution provides more, or less, than what is required.	The 2022 Annual Acquisition Report (AAR), published on April 4, 2022, provides information on the IESO's decision making methodology that is used to determine planned actions to meet identified reliability needs, including the need for non-competitive procurement mechanisms. The AAR includes a summary of information on the needs being addressed (with references to additional public information available through the Annual Planning Outlook or Transmission Plans, as appropriate), the proposed solution, and the risks that were considered in determining the set of planned actions to meet reliability needs. When proposing a non-competitive solution, the AAR provides a signal to the marketplace that there is a need to be met, by clearly and transparently articulating the need and recognizing that a competitive process could be used in the future to meet the need if sufficient resources are available to support competition. The AAR also includes a discussion on activities to enable greater competition and, where needs exist in a specific location, encourages

Report	Recommendation Number	Recommendation	IESO 2024 Update to the OEB
			competition by specifying those needs as design considerations in long-term RFPs. The IESO expects to continue to provide this information to stakeholders in future AARs.
September 2, 2021	3-8	To facilitate the inclusion of projects with broader public benefits in competitive procurement processes, the IESO should separate non-electricity system costs and benefits from the electricity system cost-benefit analysis and publish the results.	The IESO is aware that some facilities or projects may provide public benefits beyond those related to the electricity system. Through the operationalization of the Resource Adequacy Framework via the Annual Acquisition Report and subsequent procurement activities, the IESO is shifting the procurement focus from a resource-centric to a system-centric approach, where eligible facilities compete to provide the electricity services needed to maintain a reliable electricity system. The identified needs, ensuing procurements, and ultimately procurement outcomes will help to transparently identify the benefits and costs to provide these electricity services. However, accounting for any other non-electricity benefits that may materialize from a procurement, outside of the IESO's objects, is not part of the IESO's mandate. Other public benefits are best assessed and published by the appropriate branch of Government, who

Report	Recommendation Number	Recommendation	IESO 2024 Update to the OEB
			can assign a value to the public benefit, and determine how much of the cost of that benefit should be attributed to electricity ratepayers. In these instances, the Government is best positioned to provide policy direction to the IESO in cases where these non-electricity benefits are to be factored into electricity system decisions. With regard to bilateral arrangements, including those that are part of the Ministry of Energy's Unsolicited Proposal assessment process specifically, the IESO would be unable to publish the results of its assessments as these contain third-party confidential information. Furthermore, as part of the Unsolicited Proposal process, this information is provided as confidential advice to government. Information on the project valuation framework used by the IESO to assess a broad range of projects, including Unsolicited Proposals, is available on the IESO's website
September 5, 2024	24-1-1	The Panel recommends that the IESO review the benefits and costs of continuing the Intertie Offer Guarantee (IOG) in the real-time market after the deployment of the Market Renewal Program. The review should consider imports arranged outside of the	The IESO agrees with the Panel's recommendation of a review of the real-time IOG with respect to reliability and efficiency. Upon the launch of the Market Renewal Program, the IESO will continue to monitor and evaluate the real-time IOGs in this regard. A

Report	Recommendation Number	Recommendation	IESO 2024 Update to the OEB
		Day Ahead Market and quantify the extent to which, the IOG: enhances the reliability or adequacy of the electricity system; contributes to inefficient import schedules; and dampens real-time market prices thus contributing to other potential real-time scheduling inefficiencies. e Panel recommends that the IESO review the benefits and costs of continuing the Intertie Offer Guarantee (IOG) in the real-time market after the deployment of the Market Renewal Program. The review should consider imports arranged outside of the Day Ahead Market and quantify the extent to which, the IOG: enhances the reliability or adequacy of the electricity system; contributes to inefficient import schedules; and dampens real-time market prices thus contributing to other potential real-time scheduling inefficiencies.	minimum of six months operating the new market will be required for a meaningful assessment before the IESO can report on any initial findings.

Market Power Mitigation Working Group – Overview

Introduction:

The following provides a high-level overview of the function and purpose of the Market Power Mitigation (MPM) working group. Following the appointment of working group members, a Terms of Reference will be finalized with members and posted on the MPM working group webpage.

Purpose:

The working group was established at the request of the IESO Technical Panel to assist in identifying any potential unintended outcomes of the MPM framework and recommending means to address any such unintended outcomes. The MPM working group is an advisory body to the IESO and the Technical Panel and consists of both IESO staff and representatives from potentially impacted parties.

The working group will perform its function until a date that is one year following the market transition completion, or for such longer period as may be determined by the IESO, the Technical Panel, or the working group. Participation is on a voluntary basis.

Objectives:

1. Develop a framework for reviewing potential unintended outcomes of the MPM framework, including the development of an approach for prioritization of issues.
2. Advise on assessment and prioritization of issues, and solutions to potential unintended outcomes from the MPM framework.
3. Provide recommendations related to existing recourse mechanisms or propose alternatives if existing recourse mechanisms are not able to address material issues that may be identified.

Qualifications:

1. Advanced knowledge and familiarity with the IESO's market renewal initiative, and specifically the MPM framework.
2. A level of technical and/or commercial knowledge and expertise in the operation of resources relevant to their represented constituency and electrical power systems.

3. A breadth of knowledge and experience working within both Ontario’s electricity sector and the constituency they represent.
4. A strong understanding of the market rules, structure and/or operations of Ontario’s electricity market.

Member Commitment:

1. Members will commit to participating for the duration of the working group, or at minimum one year, as contemplated in the Market Rules, or other such duration as determined by the IESO. The first meeting is expected to occur in early Q1 2025.

Administration:

1. Working group meetings will be pre-scheduled where possible.
2. All meetings will be in-camera. Subject to any confidentiality considerations, materials will be made public on the IESO’s website - including Terms of Reference, meeting agendas, and formal presentations.
3. Meeting format (i.e. in-person, remote, hybrid) will be determined by the working group members.

Independent Electricity System Operator
1600-120 Adelaide Street West
Toronto, ON M5H 1T1
t 416.967.7474
www.ieso.ca

Memorandum

To: **MRP Implementation Engagement Stakeholders**

From: Tom Chapman, Sr. Manager, Wholesale Market Development

Date: September 22, 2022

Re: Market Renewal Program Business Case Validation

Following the establishment of a new project schedule and budget, the IESO undertook a review of the MRP Business Case originally developed in 2019. The IESO concluded that the Business Case remains sound, and the renewed market will deliver substantial net financial benefits of at least $700 million to Ontario consumers over the first 10 years of operation.

The review included an assessment of whether the expected benefits, costs, and other underlying assumptions have materially changed given a refreshed MRP project schedule and budget, as well as an updated view of the IESO's forecasted demand and supply projections. The updated net benefits are lower than the 2019 calculated estimate of $800 million as implementation and costs to operate the new market have increased by $92 million, as some of these costs were unknown during the 2019 Business Case preparation. The new market will still yield the same benefits from quantifiable market efficiencies and the elimination of unnecessary congestion management settlement credits (CMSC) of $975 million over the first 10 years. The updated net present value of the program is $266 million which falls within the 90% probability range of NPV values that were calculated for the 2019 Business Case. Other benefits, through optimization and operational certainty, that were not quantified in the Business Case are expected to increase as the sector is evolving to include new and more diverse resource types, such as storage and hybrids.

The renewed market will build on and enhance the IESO's ability to deliver on core priorities of preparing for future transformation of the sector and ensuring cost-effective reliability of the Ontario electricity system. Efficient operation of existing resources and effective integration of new resource types is dependent on the foundational improvements MRP will deliver – prices that reflect costs in the different regions across the province and significantly improved optimization of supply resource scheduling and dispatch. Effective integration of storage and other new resource technologies would not be possible in today's two-schedule market without significant compromise to their potential and increased integration costs, especially with growing future uncertainties related to fuel and resource development costs. Together the improvements delivered by MRP will significantly improve our ability to provide optimal use of resources available on any given day, and send clear signals to identify where additional resources are needed in the future.

Key Updates and Findings of the Validation of the MRP Business Case

1. Quantifiable Benefits

The estimated total benefits of $975M from 10 years of operating the new market remain the same with a shift in the launch of the new market from 2023 to 2025. These benefits include $525M from market efficiency improvements and $450M from avoiding unnecessary congestion management settlement credit payments.

Market Efficiency Benefits

The calculated market efficiency benefits of $525 million in the first 10 years are achieved through more efficient unit commitment and optimization, improved intertie pricing, and locational pricing incentivizing increased resource competition. These benefits are not affected by any schedule and budget changes, or changes in the sector and the associated forecasts because the design of the market has not fundamentally changed. Each of the quantified benefits are tabulated in the table below and further discussed.

Market Efficiency	10 Years of Efficiency Benefits ($M)
More Efficient Unit Commitment	$190
Improved Intertie Pricing	$285
Increased Resource Competition	$50
Total Efficiency Benefits	$525

The benefits of more efficient unit commitment were determined based on assessing the inefficiency of the existing process to commit resources that require lead time to come on-line and minimum operating runtimes once connected to the grid. This calculation is still valid as there will continue to be non-quick-start resources with start-up costs and minimum operational requirements that would be inefficiently scheduled in the absence of MRP. With the potential for a decarbonized and decentralized resource mix, the renewed market will be necessary for driving efficient outcomes and managing resources' operational requirements.

The benefits of improved intertie pricing also do not change with the refreshed project schedule. The Ontario market is directly connected to the Mid-Continent Independent System Operator (MISO) and New York Independent System Operator (NYISO) electricity markets and indirectly to the Independent System Operator of New England (ISO-NE) and the PJM Interconnect. These links to external markets remain and will require efficient price signals to indicate when it is economic to export or import energy. The current two-schedule pricing market sends incorrect signals leading to volumes of energy flowing out of Ontario settled at a price that does not match the costs to produce the energy. These inefficiencies were modelled in the 2019 Business Case and recent monitoring shows that these inefficiencies continue to occur where the annual estimate used in the Business Case is a lower bound of the potential benefits.

The benefits from increased resource competition also do not change with the refreshed project schedule. These benefits were determined by assuming a subset of the resource fleet would be more proactive and respond more aggressively to transparent prices. The 2% reduction in offer prices was already, and continues to be, a conservative estimate based on published literature on increased competition from market design enhancements, and from updated projections on the future demand forecast.

Elimination of Unwarranted Congestion Payments

The new market would avoid $450 million of unwarranted congestion management settlement credit (CMSC) payments in the first 10 years. The current market incurs congestion management settlement credits of which unnecessary constrained-off payments will be eliminated by the new market. The elimination of these payments are not affected by any schedule and budget changes over the first 10-year period of operating the new market. On an average annual basis, $45 million would be avoided by Ontario consumers. This level of avoided payment with the new market is consistent with the amount of constrained off payments charged to Ontario consumers in 2021.

Total Benefits

The total benefit to Ontario consumers from MRP is the sum of market efficiency benefits and the elimination of unwarranted congestion management settlement credit payments. With the IESO's conservative assessment of the total benefits, in the first ten years of operating the new market the total benefits are unchanged from the 2019 Business Case calculation and amount to $975 million.

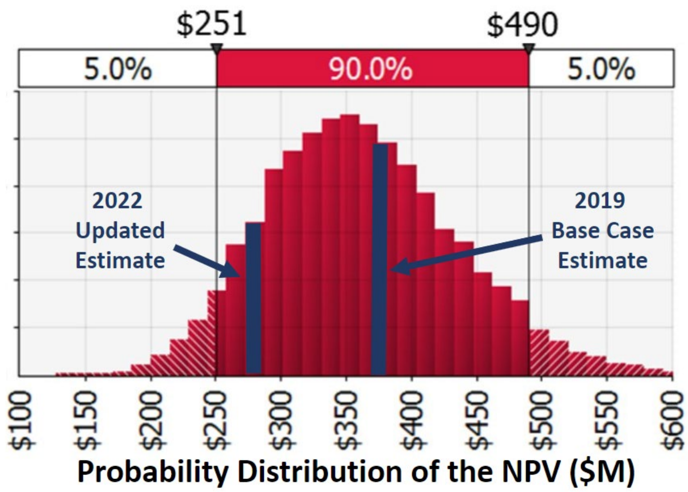
Total Benefits	10 Years of Benefits ($M)
Market Efficiency Benefits	$525
Eliminated CMSC Benefits	$450
Total Quantifiable Benefits	$975

2. Implementation and Operating Costs

In the original 2019 Business Case, MRP was expected to cost $170 million and be implemented in 2023. After the program had been implemented there was expected to be ongoing incremental maintenance costs, estimated at an additional $6 million over the first 10 years following implementation. At the time of developing the Business Case in 2019, it was not yet known if incremental staff would be required to operate the new market. With more certain costs and development schedules confirmed by vendors, the implementation timeline has been extended to 2025 with a new implementation cost estimate of $233 million. Further, the completion of the MRP Detailed Design in 2021 has also allowed for more accurate assessment of the ongoing costs over the first 10 years of operations. The total implementation and operation cost estimate, including the additional staff[1] for ongoing operation of the renewed market is $268 million or $92 million more than assumed in 2019.

3. Net Financial Assessment

Using the updated implementation and operating cost values and the same benefits, the net financial assessment of the Business Case was recalculated. The updated net present value of MRP is $266 million which falls within the 90% probability range of NPV values, which are between $251 million and $490 million as calculated for the 2019 Business Case. Despite increased cost estimates, the NPV of MRP remains strong, and underscores the value to ratepayers for implementing MRP. The figure below compares the original 2019 probability distribution of the NPV for MRP, with the 2019 base case value and the 2022 updated value estimate illustrated.



4. Benefits Not Quantified

The 2019 MRP Business Case included case studies and discussion of qualitative benefits. These included better operational and financial certainty with a day-ahead market and broader market benefits. The broader market benefits include improved signals for supporting investment and competition, indicating the need for system flexibility, and reduced energy curtailment and spilling. Given the need to acquire incremental capacity to meet increasing system needs and the focus on investigating pathways to decarbonize the electricity fleet, these unquantified benefits are expected to be even larger and of increased importance since 2019 when the Business Case was published.

[1] MRP will introduce new features and tools that require additional resources for market operations, monitoring and ongoing maintenance and support.

In particular, with the larger anticipated volume of storage resources, the single schedule design of MRP is essential. The current IESO initiatives for storage integration and enabling new resources will be facilitated with the single schedule design as storage and other emerging resources require clear locational price signals to know when to operate economically.

Minutes of the IESO Technical Panel Meeting

Meeting date: September 10, 2024
Meeting time: 9:00 a.m. - 10:52 a.m.
Meeting location: In-Person/Video Conference

Chair/Sponsor: Michael Lyle

Scribe: Trisha Hickson, IESO

Please report any suggested comments/edits by email to engagement@ieso.ca.

Invitees	Representing	Attendance Status Attended, Regrets
Jason Chee-Aloy	Renewable Generators	Attended
Rob Coulbeck	Importers/Exporters	Attended
Dave Forsyth	Market Participant Consumers	Attended
Jennifer Jayapalan	Energy Storage	Attended
Indra Maharjan	Consumers	Attended
Forrest Pengra	Residential Consumers	Attended
Robert Reinmuller	Transmitters	Attended
Joe Saunders	Distributors	Attended
Vlad Urukov	Market Participant Generators	Attended
Michael Pohlod	Demand Response	Attended
Lukas Deeg	Generators	Attended
Matthew China	Energy Related Businesses and Service	Attended
David Short	IESO	Attended
Michael Lyle	Chair	Attended
Secretariat		

Invitees	Representing	Attendance Status Attended, Regrets
Trisha Hickson	IESO	Attended
IESO Presenters/Attendees		
Stephen Nusbaum		
Darren Byers		
Jo Chung		
James Hunter		
Jessica Savage		
Candice Trickey		
Carita Edwards		
Paula Lukan		
Adam Cumming		

Agenda Item 1: Introduction and Administration

Trisha Hickson, IESO, welcomed everyone joining the meeting.

The meeting agenda was approved on a motion by Joe Saunders.

The September 10, meeting minutes were approved on a motion by Forrest Pengra.

Introductory Remarks from the Chair:

Michael Lyle, Chair welcomed everyone and thanked Technical Panel (TP) members for their participation and contributions during the additional sessions held over July and August to discuss Market Renewal related items ahead of the today's meeting. Mr. Lyle pointed to the Panel's commitment and thoughtful feedback as being critical to ensuring the market rules reflect the design. In addition, Mr. Lyle noted that the IESO is still accepting nominations for the Market Participant, Consumer representative. The posting is still available on LinkedIn. Mr. Lyle also noted that the IESO Board has approved the 2024 Capacity Auction Market Rule Correction Amendments, effective September 20th.

Agenda Item 2: Engagement Update

Trisha Hickson, IESO provided an update on the prospective schedule which can be found on the Technical Panel webpage. Ms. Hickson identified upcoming sessions as part of the IESO September Engagement Days and encouraged Technical Panel (TP) members and observers to attend.

Agenda Item 3: Market Renewal Program (MRP) – Final Alignment Batch

Jessica Savage, IESO noted that the proposed vote to recommend of the MRP market rule amendments via the Final Alignment (FA) batch, concludes more than 30 TP meetings over four years. Ms. Savage noted the TP's role is to provide advice to the IESO Board on whether the market rule amendments meet the design intent, and these rules have been developed with feedback from stakeholders for the past eight years. On behalf of the IESO, Ms. Savage thanked TP members and stakeholders for their collaboration and noted that the many years taken reflects the extent of engagement in response to stakeholder concerns with adjustments made along the way. The IESO also recognized that MRP is new and complicated, and that there will likely be growing pains after go-live. In consideration of this challenge, the MRP implementation and Market Power Mitigation (MPM) working groups will continue their respective stakeholder engagement efforts.

Stephen Nusbaum, IESO, provided a presentation outlining stakeholder feedback on the FA Batch. The presentation included stakeholder comments, the IESO's response and revisions to the Market Rules and Manuals. In addition, Mr. Nusbaum presented supplemental materials (posted Sept 6) on TP member feedback specific to the proposed market rule language on establishing an MPM working group (MPM WG).

All presentations can be found on the Technical Panel webpage.

Jason Chee-Aloy asked what the IESO's plans were if additional market rule amendments were required after IESO Board approval of the FA batch and following testing. Specifically, he asked whether the TP would stick with the same cadence of meeting and how the baseline of the rules would be handled.

- Candice Trickey, IESO, noted that the regular cadence of TP meetings will be scheduled, and additional meetings can be booked as required to ensure priority issues are addressed. Ms. Trickey reminded the panel that there is also the urgent market rule amendment process that can be utilized if required.

Mr. Chee-Aloy asked for confirmation whether market participants (MPs) also had the right to raise issues through the TP or propose market rule amendments themselves.

- Ms. Trickey confirmed this was correct.

Vlad Urukov asked whether the discretion to delay the designation of narrow constrained areas (NCAs) and dynamic constrained areas (DCAs) until six months after go-live was a firm commitment from the IESO.

- Mr. Nusbaum responded that yes, it is a firm commitment. Mr. Nusbaum further clarified that previous version of the market manuals engaged on with stakeholders, already states that once an NCA is published, it cannot come into effect sooner than 30 business days later. The timing for the start of the DCAs assessment process was unclear and the IESO made a further amendment to ensure that there was no ambiguity. and that the IESO has the ability, once the Potential Constrained Areas (PCA) were published, for the DCA to come into effect no sooner than 30 business days later.

Mr. Urukov asked for clarification as to where in the market rules the timing for the first publication of the PCA/NCA is described, as it was described in the presentation to the panel on August 15.

- Mr. Nusbaum noted this language is not explicitly documented as part of the market rules. The market rules only require that the IESO publish results once per calendar year, rather the timing commitment discussed in August by the IESO detailed how the PCAs would be rolled out as part of the transition to the renewed market. It was further noted that this commitment has been documented in presentation materials and meeting minutes.

Lukas Deeg asked regarding pseudo-units *(PSUs - slide 6 - IESO to consider on a case-by-case basis PSU registration requests where not all resources designated as part of that PSU are connected to the IESO-controlled grid at the same connection point)*, whether there are situations where the IESO having completed an assessment, might reconsider that assessment at some other point for reliability purposes?

- Mr. Nusbaum noted the one-time assessment is done at the time of registration. There is no continuous process to review connections. If something material was to cause a reliability issue to the grid, the IESO can constrain a resource to address the concern. Mr. Nusbaum noted that it is an unlikely scenario where the IESO would grant an exception to a PSU registration request where not all resources are connected at the same connection point, and then find itself where it cannot reliably operate the grid in that configuration thereafter. There would need to be an extraordinary event or change to drive the IESO to take actions that would lead to the need for a change in registration.

Mr. Deeg asked for confirmation that it would only be at the time of registration where reliability concerns would prevent a combined cycle plant from being permitted to be registered as a PSU.

- Mr. Nusbaum noted that if the IESO's assessment is that there are reliability concerns at the time of registration then yes, that is correct.

Mr. Deeg asked if there is a combined cycle plant that has two separate connection points and is not PSU eligible, can they manage their operations through offers?

- Mr. Nusbaum acknowledged, that yes, they can.

- Ms. Trickey noted that if a unit that is contemplating and assessing how to configure their facility, a conversation would be had with the IESO upon registration to determine a path forward.

- David Short, IESO, noted that if a participant wants to change their connection, they are able to do so by applying through the connection assessment process.

Mr. Deeg noted that there is one MP who is considering changing their connection because of complications related to MRP implications. Mr. Deeg indicated that he would assume the market participant is looking for confirmation from the IESO whereby the IESO would allow PSU resources to be connected at different connection points.

- Mr. Nusbaum noted that the IESO is aware of the facility and has started to look into their connection to be able to provide advance guidance. He noted the benefits of PSUs, and that the IESO would try to facilitate where possible.

Mr. Deeg asked about the point made on slide 6 relating to Make Whole Payment eligibility (allowance for certain non-quick start resources that are not GOG-eligible to be eligible for make-whole payments up to their minimum loading point), and whether there might be any additional changes required?

- Mr. Nusbaum noted that the IESO's understanding is that the edit proposed in the FA Batch will address the issue. If any additional gaps or issues arise, the IESO is willing to further discuss.

Mr. Chee-Aloy asked for clarity regarding the previous statement of the IESO only needing to document the delay in declaring NCAs through the meeting minutes and presentations?

- Mr. Nusbaum explained that the IESO does not believe there is a need to codify this language into the Market Rules or Market Manuals. The IESO has the necessary authority to designate PCAs at any point within the first year after go-live, and the IESO has committed to delaying the initial designation for 150 calendar days (with a further 30 business days before the NCAs and DCAs would be used in mitigation assessments).

Mr. Chee-Aloy asked why the IESO would not consider inserting language to address the IESO's commitment under Market Rule 4.8.1-RO7 page five rule B.1.1?

- Mr. Nusbaum noted that the IESO has already expressly committed to the timelines discussed and that this commitment is documented in TP minutes and presentations.

- Ms. Savage reinforced that the IESO has made a public record and commitment in relation to this matter and believed that including language within the Market Rules is not required.

Mr. Chee-Aloy acknowledged but noted that MPs would be more comfortable should these commitments be integrated into the Board materials. Transparency in providing the exact language or information being brought forward to the IESO Board regarding the designation of constrained areas would provide comfort.

- Mr. Nusbaum agreed and confirmed that the commitment will be integrated into the Board materials, and that the materials submitted to the Board when asked to consider adopting market rule amendments are posted publicly, which contributes to further transparency and documentation of the IESO's commitment.

Mr. Chee-Aloy acknowledged and accepted this approach.

On another matter, Mr. Urukov asked if there was an update on any engagement regarding the interpretation bulletins.

- James Hunter, IESO, noted that he expected MACD would be providing an update, and that he would also expect the update to be prior to MRP go-live.

Mr. Urukov asked if the IESO would be open to the MPM WG including references to recourse within the MPM WG ToR.

- Mr. Nusbaum noted, yes, the IESO would be open to that if deemed to be important to do so by the MPM WG itself.

Mr. Urukov stated his understanding of the four incremental changes proposed by the IESO during the August 15 meeting that was captured in a presentation from that date. Mr. Urukov stated the challenges in finding these commitments contained in presentations and questioned why these incremental changes would not be put into the proposal package. Specifically, Mr. Urukov questioned why the IESO would include the MPM WG commitment into a transitional market rule, however would not integrate the IESO's commitment to not issue ex-post mitigation assessments into the market rules.

- Mr. Nusbaum noted that the market rules already state that the IESO "may" issue notices in regard to physical withholding, thereby indicating discretion and questioned what else might be needed.

Mr. Urukov expressed concern over the reliance on the term "may" and that the IESO has committed to go over and above which is not articulated in the market rules.

- Mr. Hunter noted the difference between the two points. The creation of a working group is establishing a new action that would not otherwise have taken place, whereas with ex-post physical withholding, the IESO already has discretionary authority and the IESO has made a public commitment with respect to how the IESO will exercise that existing discretion for a period of time. The Market Rules are meant to capture the rights, obligations, and authorities of the IESO and MPs and in this case the discretionary authority is in the Market Rules and what the IESO is doing is making a specific commitment with respect to how the IESO will exercise that discretion for a period of time. The IESO's view is that this does not change the discretionary authority.

Mr. Urukov asked for confirmation of the IESO's commitment.

- Mr. Nusbaum noted that the commitment is that the IESO will not assess physical withholding in isolation for a period of time post-go live. The IESO recognizes that challenges could occur in how ex-ante mitigation and physical withholding are working and that there could be complex interactions that had not been anticipated that may require further analysis. The IESO will consider this information prior to deciding whether to issue a notice of physical withholding. The commitment is to work with the sector to ensure the appropriate outcomes.

Mr. Urukov asked if the IESO would pause sending out ex-post notices until issues are resolved related to excessive amounts?

- Mr. Nusbaum noted there may be instances where notices would be issued. It is not the intent to pause the entire mechanism. Mr. Nusbaum added that in circumstances where the IESO believes there are extenuating circumstances, it would be appropriate to delay issuing notices.

Mr. Urukov asked why the presentation is noting the pause of ex-post mitigation assessments?

- Ms. Savage noted the IESO is highlighting that if there are unintended interactions, the IESO has the ability to proactively exercise discretion.

- Mr. Nusbaum noted the IESO will pause issuing notices of physical withholding in those situations where the IESO is seeing unintended outcomes such as excessive volumes of physical withholding that are not aligned with the design intent.

Mr. Urukov stated that what he believes is excessive may be different than what the IESO considers excessive.

- Ms. Trickey noted that the IESO will look at both individual cases and broader situations. If the IESO finds there are broader situations contributing to an unexpectedly large volume of cases, then the IESO could pause all similar cases for the time being until the root issue is identified and addressed.

Mr. Urukov noted his concern remains that if an MP received an excessive number of notices which may be different than the IESO thinks, it is not clear what an MP could do in this case.

- Ms. Savage noted that there would be discussion with the IESO and there is an opportunity to table issues with the MPM WG which could provide recommendations to pause.

Mr. Urukov recommended that the IESO make this as part of the MPM WG ToR.

- Ms. Savage noted that it is still the IESO's discretion, and it is not the intent to automatically pause ex-post. The IESO needs to maintain discretion, and this is noted in the language used of "may".

The IESO noted that more discussion can take place on this matter offline.

Mr. Urukov noted a concern with respect to ex-ante market power mitigation. Under the current settlement rules there is a clear path from a notice of disagreement to a notice of dispute, that requires as an initial step the filing of a notice of disagreement through the receipt of a settlement statement. However, ex-ante market power mitigation will be different as the impact will be less direct. Offers will be replaced with mitigated offers, resulting in different schedules and different prices. Mr. Urukov added, so where the concern lies is where there might be an inappropriately mitigated price, but it may not be possible for a market participant to recognize this within the time restrictions for filing a notice of disagreement.

- Mr. Hunter noted that the notice of dispute process is available to address any disagreement between the IESO and market participants with respect to the IESO's application of a market rule. There is no general requirement to file a notice of disagreement in advance of a notice of dispute. The exception to this general principle is with respect to disputes regarding some settlement outcomes. The market rules establish a notice of disagreement process which must be followed as a precondition to filing a notice of dispute, and that process includes timelines for filing notices of disagreement. The purpose of the notice of disagreement process is to catch issues that could be identified by market participants through review of their preliminary settlement statements before the IESO settles the market; it is more administratively burdensome to correct such errors following the issuance of a final settlement statement because the correction requires re-settlement of the entire market. However, market participants can otherwise challenge the IESO's application of market rules without having to first commence a notice of disagreement, and arbitrators can make appropriate awards. In the hypothetical case where there is an unintended outcome in the ex-ante process that could only have been identified after the fact, and that outcome gives rise to a disagreement between the IESO and a market participant regarding the IESO's application of the relevant market rule(s), the participant can challenge the IESO's application of the rules outside the time restrictions for filing a notice of disagreement.

Mr. Urukov asked for clarity on what would be subject to a notice of disagreement?

- Mr. Hunter stated that the notice of disagreement process is complex but clearly set out in the market rules. He added that it is important to note that the notice of disagreement is a special channel to address disputes for settlement purposes, but that it is not necessary for other disputes to proceed through the notice of disagreement process.

Mr. Urukov asked whether, if the MPM WG brings forward an issue, and the IESO then disagrees with that issue, could that issue still be taken by an MP as a matter of a subject of dispute?

- Mr. Hunter noted that yes that is how the dispute process is intended to work.

Mr. Chee-Aloy commented that this is the crux of why the MPM WG has been created and why he continues to advocate for the group to address recourse. Using ex-ante mitigation as an example, it is a very mechanical process subject to technical assumptions. The IESO can state that they are applying the rules as they are intended, but what is behind the calculations are a lot of gray areas. Mr. Chee-Aloy stated his belief that the MPM WG is a compromise to addressing this issue and sees it as a way forward. Mr. Chee-Aloy shared that there is historical scepticism related to the application of the dispute process in Chapter 3.

- Mr. Hunter noted Mr. Chee-Aloy's position that there was a problem with relying on the dispute resolution process to address issues related to ex-ante mitigation and noted as well that skepticism had been expressed about the sufficiency of the dispute process to address such issues. Mr. Hunter acknowledged that there are cases where an arbitrator could agree that the IESO properly applied rules as drafted, but where the real issue is that a participant may believe that a market rule should have been drafted differently. Mr. Hunter noted that there was nothing special about ex-ante as far as that concern goes. It may be that in some cases the IESO did follow the rules correctly and the best way to address a subsequently determined issue in those cases could be by amending the rules, rather than disputing them.

Mr. Chee-Aloy noted that MPM is a special case as it is new and a different framework being introduced into the wholesale market design that will impact the economics of the market in areas with transmission constraints. Based on past work including historical examples of narrow constrained areas the generators and storage providers in northern Ontario could be subject to long periods of MPM that will only negatively impact their economics. That has never happened before. This is a new untested impactful feature, and this is why the IESO has been hearing concerns being raised from stakeholders for months.

- Mr. Hunter noted the comment provided and stated that he did not intend to downplay the significance of the new framework, and that he appreciated the comment.

Mr. Deeg noted his understanding of the broad language around unintended outcomes but expressed a remaining concern on how the MPM WG might apply the processes and procedures for recourse purposes. It would be helpful to provide additional clarity.

- Ms. Savage noted that the response to the question has been covered by Mr. Hunter's previous remarks which explained the procedures.

Mr. Deeg clarified asking if the intent is that if the MPM WG flags harm that was caused by unintended outcomes, could that market participant rely on a process for recourse?

- Mr. Hunter noted that should a dispute come up between an MP and the IESO and the same issue is reviewed by the MPM WG, which agrees with the MP, that finding could be persuasive to the IESO or an arbitrator, depending on what the issue was about.

Mr. Deeg stated that one of the challenges is there may be issues with more than just an application of the Market Rules. For example, the MPM WG may identify a need for specific requirements that outline the thresholds for conduct and impact tests. There could be broader issues than just how the market rules are applied.

- Mr. Hunter indicated that it is hard to discuss these things in the abstract, but that it was fair to say that there will be some cases where there will be a clear disagreement about whether a market rule was correctly applied, all things considered, and others where the market rules do not at all imply or require an outcome, but where the question is about whether they should be amended going forward and there are a myriad of cases between the two.

Rob Coulbeck noted that the thresholds themselves are an issue, as there is not a lot to back up the operators or price thresholds. The pricing thresholds are included in the Market Rules. As such, is this something that could be disputed, if the MPM WG sees a significant amount of mitigation occurring as a result of the pricing thresholds? Should there be a term for this included in the MPM WG Terms of Reference (ToR) to address how the MPM would look at this?

- Mr. Nusbaum noted that this topic is something the IESO and MP would discuss to align on in identifying if the MPM Framework is doing what it is intended to do. If they mutually agree that it is not doing what it is intended, then we would agree to update those thresholds. As such, the IESO is not sure it would not need to flow through the dispute resolution process rather than a working group designed to continually evolve and improve the MPM Framework.

Mr. Coulbeck noted that it would be beneficial to have something identified in the MPM WG ToR that if the operating reserve thresholds are imposing mitigation on a frequent basis, it should be reviewed.

- Ms. Savage stated that the purpose of the MPM WG is to first identify and prioritize issues with input from technical experts. Once it is agreed that there is an issue that needs resolving, the WG can then discuss potential solutions. The IESO and Technical Panel should first align on the issues, then that leads to potential fixes rather than beginning to solution hypothetical issues at this time.

Mr. Urukov noted the importance of this conversation is to have assurance that the group will have the right mandate and identify issues that will face the WG.

- Ms. Savage noted these discussions will be better suited for the next Technical Panel meeting in October which will discuss the ToR of the MPM WG.

Mr. Urukov added that there may be challenges determining what the group should discuss due to ambiguities with respect to causes of potential issues.

- Ms. Trickey agreed that it may be difficult to accurately identify issue and their causes, but the benefit of having a group is to assist in that work.

Mr. Deeg stated that many market participants are likely to rely on the MPM WG for MPM issues and hence why the recourse issue is so important. Mr. Deeg added that MPs do not want to go to the OEB, and neither does the IESO. MPs will need to preserve the right to dispute.

- Mr. Hunter noted the IESO will not tell an MP that they cannot file a notice of dispute about an issue they have with respect to the IESO's application of the market rules. Whether an arbitrator would agree that a participant is entitled to an award is another question. But to be clear, if the MPM WG recommends that the market rules should be changed in some way, an arbitrator will not order that the IESO should apply the change retroactively. Arbitrators will not do that. An Arbitrator makes a decision about what the rules required at the time they were applied, not what they might have required if a better or different framework had, counterfactually, been in place. Mr. Hunter noted that it was difficult to speak in the abstract about these things, but that it was also important to remember that much of the dispute resolution process is focused on good faith negotiations, before the dispute proceeds to arbitration. There is no time limit to good faith negotiations under the rules, and the reason for that is to afford the opportunity for market participants and the IESO to work through complicated issues and arrive at equitable and appropriate solutions. The IESO takes the good faith negotiation process seriously and has a long track record of addressing issues in dispute in good faith.

Mr. Chee-Aloy asked in relation to proposed language on the purpose of the MPM WG if the IESO would be willing to add the words "and reconcile" after "means".

- Mr. Lyle asked for further clarification of the proposed edit.

Mr. Chee-Aloy, explained that without using the term recourse, this edit may help address some the concern from the Technical Panel members to help guide what the terms of reference could be for the MPM WG.

- Ms. Savage noted the earlier answer from the IESO stands regarding not including this proposed edit.

Mr. Chee-Aloy asked if it would make sense to also include an edit to the length of the MPM WG by changing it from one-year to two.

- Mr. Nusbaum and Ms. Savage noted that this may not be the best approach to include within the market rules as it would be better advised to see how the working group progresses instead of committing to a longer period to time and being held to that timeline should the working group not be functioning as intended.

Mr. Chee-Aloy requested that the Technical Panel be involved in informing the decision to extend the duration of the MPM WG.

- Ms. Savage noted that because the MPM WG will be reporting back to the TP as well as to the IESO, TP will therefore be involved in any discussions with respect to extending the duration of the working group.

Upon completion of comments and the presentation Mr. Lyle called the panel for a vote.

Robert Coulbeck moved the vote to recommend the MRP Final Alignment Batch of market rule amendments for IESO Board approval.

The Technical Panel voted unanimously in favour of recommending the MRP market rules to the IESO Board for approval – see TP member comments attached.

Other Business

No other business was brought forward.

Adjournment

The meeting adjourned at 10:52 a.m.

The next regular TP meeting will be held on October 15, 2024.

Action Item Summary

Date	Action	Status	Comments
March 23, 2021	In relation to MR-0448-R00 market rule amendments, the IESO will periodically review the availability of Error and Omissions insurance for negligence.	Open	

Member Vote and Rationale – Market Renewal Program: Final Alignment Batch

IESO Technical Panel, September 10, 2024

The vote to recommend the proposed market rule amendments (MR-00481-R00-R13) for consideration to the IESO Board of Directors passed unanimously at the September 10, 2024, Technical Panel meeting.

MR-00481-R00-R13 – Market Renewal Program: Final Alignment

TP Member	Vote and/or Rationale
Michael Pohlod (Demand Response)	For
Indra Maharjan (Consumer)	For
Forrest Pengra (Residential Consumer)	For Throughout the entirety of the process of MRP and more specifically MPM, I have listened along carefully to both the IESO and fellow Technical Panel members. From the residential consumers perspective, it's critical to understand regulation and industry, as they intertwine with real-world consequences and impacts on all consumers in the province. Balancing the economics of both affordability and attractiveness to industry will remain the most difficult part of the new market. I feel throughout the entirety of the process, both sides worked well together to voice concerns and find

TP Member	Vote and/or Rationale
	opportunities. Where opportunities coexist with enhanced economic protection mechanisms, the consumer benefits. I felt confident in my yes vote prior to being asked the question, and even more so after the unanimous response.
Lukas Deeg (Generator)	For i) The IESO has been seeking feedback from market participants on MRP market rule batches since 2021; ii) The amendments within the Final Alignment Batch are generally in line with the approved MRP detailed design document; iii) To help address market participant concerns related to market power mitigation, the IESO committed in their August 15th presentation and subsequent discussions to: a. enhance end-to-end user testing; b. effectively delay the designation of constrained areas to a minimum of six months after MRP Go Live; c. provide preliminary data on potential constrained areas and narrow constrained areas based on the first ninety days after MRP Go Live; d. use extra discretion when assessing ex-post mitigation for physical withholding to avoid unintended consequences under specific circumstances; and e. establish the Market Power Mitigation Working Group prior to MRP Go Live; iv) The IESO remains open to further amendments to the market rules if issues or challenges are identified through testing or by market participants; and v) The IESO has committed to continue to work with: a. the Technical Panel to establish the terms of reference of the Market Power Mitigation Working Group; b. the Technical Panel and stakeholders to ensure knowledgeable representatives from a cross section

TP Member	Vote and/or Rationale
	of market participants are effectively represented on the Market Power Mitigation Working Group; c. market participants who wish to register their facilities as a pseudo unit to address potential dispatch compliance concerns ahead of MRP Go-Live; and d. the market participant who has a non-quick start unit that is not GOG eligible to ensure the amended provisions introduced in the Final Alignment Batch addresses their unique circumstance. Implementation remains an outstanding concern for market participants and several critical components related to market renewal remain outstanding. The contracts between the IESO and generators still require amendments and agreement between parties to reflect the market changes brought on by MRP. Reference level discussions between the IESO and generators are ongoing, and system testing is set to conclude next year. MRP requires these items to uniformly work together if the transition and framework will be successful, and generators will not fully know the implications of the transition to the new market until these are resolved. These items are outside the Technical Panel's terms of reference. However, I would encourage the IESO to continue to work with market participants to resolve these items quickly.
Jason Chee-Aloy (Renewable Generators)	For 1. conclusion of establishing Reference Levels with Market Participants for inclusion within IESO's application of Market Power Mitigation (MPM); 2. determination of Terms of Reference for the MPM Working Group, including knowledgeable sectoral membership within the Working Group; 3. outcomes regarding addressing concerns and solutions relating to hydroelectric generators, as documented between the Ontario Waterpower Association (OWA) and IESO; and 4. conclusion of amendments to contracts held between Suppliers (e.g., wholesale market participant generators) and IESO, contractually triggered by MRP

TP Member	Vote and/or Rationale
	amendments to the Market Rules. (In future, I recommend that IESO work with stakeholders to review how the role of the TP may need to change to consider explicit linkages between IESO procurement contracts and Market Rules – as no such stakeholder forum exists today to assess linkages to Market Rules and contracts administered by IESO. This is prudent because the scope of the TP was founded decades ago at a time when contracts were not used by IESO as the main mechanism to ensure resource adequacy. Rationale for this recommendation is supported by this point - if the Incremental Capacity Auction (ICA) (i.e., a Forward Capacity Market) was not discarded and continued within MRP scope (resulting in IESO not using contracts as the main mechanism to ensure resource adequacy), then the TP would have had to opine on ICA related amendments to the Market Rules and would have had to consider factors relating to electricity infrastructure investment regarding new and operating assets (e.g., generators, storage, etc.)
Vlad Urukov (Generator)	For As guided by the Technical Panel Terms of Reference, a Technical Panel vote on any Market Rule amendment, including the Market Renewal Program (MRP), is ultimately a contemplation on whether the proposed Market Rule language meets the intent of the proposed change. In the case of the MRP Final Alignment vote, the proposed changes span the entire 11 Chapters of the Market Rules as well as Market Manuals. The intent of MRP is multi-faceted and complex, covering the operation and settlement of both the Energy and Reserve markets. An additional challenge is the introduction of the Market Power Mitigation (MPM) framework, which is a layered, three-part framework that relies on the designation of constrained areas and independently set reference levels. This framework does not have an equivalent structure in the existing market. In recognition of these challenges, my vote on the alignment package of all previously voted sections relies on my review as well as the extensive stakeholder engagement over the last

TP Member	Vote and/or Rationale
	eight years and the PwC MRP DAM Engine Pre-Implementation Review and MRP PD & RT Engine Review. My vote in support of advancing to the next stages of MRP is also based on the expectation that the IESO will collaborate with participants on establishing an effective MPM Working Group, finalizing MPM reference levels, enhancing end-to-end testing, delaying the deployment of NCAs and DCAs, and exercising discretion in ex-post mitigation. Additionally, I recommend that the IESO continue to enhance the MRP Market Rules in response to future stakeholder feedback and testing outcomes.
Robert Reinmuller (Transmitters)	For While there were many challenges over the past few years, I wanted to thank IESO for listening to the engagement community and allowing teams to focus on closing specific gaps. With clear progress made last two years, there is still anxiety in the industry and providing an opportunity to work out the finite details of transactions, enabling a mechanism to evaluate recourse options, manage unintended consequences in an open and transparent way, allowed me to support the approval. With the MPM Working Group evaluating the refinements that are still required pre and post implementation, I have confidence that any remaining gaps can be dealt with as we transition to the new process.
Rob Coulbeck (Retailers or Wholesalers)	For To start I would like to compliment the IESO and the entire Technical Panel on the work everyone has done, and the compromises made in achieving the outcome of unanimous approval in the vote to recommend. In representing the trading community my vote to recommend came with minimal items of concern. There are issues around Predispatch and Real-time congestion allocation on the interties that were debated and ultimately the IESO rejected the comments of the trading community. While we are still of the opinion the decision on intertie congestion may result in reduced intertie

TP Member	Vote and/or Rationale
	transactions, this is not an item to without support of the entire Market Renewal package. I do have serious concerns though on Market Power Mitigation and its impact on creating an efficient market outcome. The components that are used to initiate and evaluate if a resource(s) may have or is considered to have market power are administrative values that have not been properly vetted and in my opinion are without valid justification. The values in question are: - BCACondThresh $25 - IBPThresh $100 - ORGCondThresh $15 - CTEnThresh2BCA $100 - CTEnThresh2GM $100 - CTORThresh2ORL $25 - CTEnThresh2ORL $25 - CTORThresh2ORG $25 - CTEnThresh2ORG $25 - CTEnMinOffer $25 - CTORMinOffer $5 - ITThresh2NCA $25 - ITThresh2DCA $25 - ITThresh2BCA $50 - ITThresh2GMP $50 - ITThresh2ORG $25 The addition of a Market Power Mitigation Working Group along with delaying the application of the Dynamic and Narrow Constrained Areas will permit evaluation of the effectiveness of the parameter for those calculations but the application of market power for Global market power and Broad Constrained Areas are to be live at implementation of MRP. While it is unlikely that Global market power for energy will bind initially, that is not the case when it comes to operating reserve. Assuming MRP goes live May 1, 2025, this will be in the height of freshet with an abundance of

TP Member	Vote and/or Rationale
	hydroelectric generation and historically limited operating reserve available. Based on my work, historically as a market participant managing a variety of resources over 22 years and analysis of MRP, the Global operating reserve threshold limit of $15 will trigger the conduct and impact test frequently in the first 2 months of MRP. Another item that will play a major role in the application of the operating reserve Global market power is the Operating Reserve Demand Curves for each class. The market rules state each operating reserve class's demand curve will be calculated based on the 99th percentile of historic prices. The IESO has indicated these values will not be available until 4th quarter of this year. It is impossible to fully appreciate the impact of the administrative threshold values until the operating reserve demand curve values are known. Additionally, it appears that negotiations between the IESO and market participants on the reference values have been frustrating for participants with the threat a resource may ultimately end up with the default values of $0.00 for price reference and full registered values for non-price related reference values. In conclusion, I fully support moving forward with Market Renewal with market power mitigation, but I believe there needs to be a thorough review of the threshold values for the conduct and impact tests.
Jennifer Jayapalan (Energy Storage)	For While I commend the effort by the IESO in reaching this significant milestone and getting us to this point, I wanted to highlight that I am recommending this batch with the recognition and understanding that there is still significant work to be done. The success of the full implementation of MRP will be dependant on an approach by the IESO that recognizes the learning curve the of industry as a whole in MPM application, limitations and outcomes. An important part of this will be the development of the Terms of Reference for the new MPM Working Group in transparent and functional way to allow it to address industry concerns. Additionally, one of the larger challenges with reviewing MRP in relation to energy storage is the limited experience and understanding within both the community and the IESO in how larger scale energy storage will be scheduled and operate under market renewal. While I am approving the MRP Final

TP Member	Vote and/or Rationale
	Alignment Batch based on existing interim storage rules within the MRP framework, there are serious challenges and shortcomings with energy storage operating under MRP. This ranges from the simple inability to set an ADE and provide operating reserve at the same time thus creating potential technology inequalities in the DAM, to reference levels and the fluctuating operating costs of charging, through to the more challenging integration of real time state of charge management. The understanding is that the implementation of MRP will provide a clear avenue to initiating and developing a full integration solution for energy storage resources. Lastly, my approval is based on the understanding that we have a long way to go ahead of May 1st and there will more than likely be changes and tweaks to be done to the rules as we work through end-to-end testing. I look forward to continuing to work with the IESO in ensuring we have a functional, working set of rules that allows for the end goal of more efficient supply, scheduling, and pricing of electricity.
Dave Forsyth (Consumer)	For I voted yes to support the final alignment batch of rules for MRP. I believe the IESO worked with the sector to address issues brought forward by the industrial consumer load community. However, I am concerned that the provision that dispatchable load must offer operating reserve in all hours they are dispatchable in the energy market to be unreasonable. The IESO has committed to work with dispatchable load to address criteria that will be considered when making determinations that dispatchable loads are exercising market power which is a very highly unlikely outcome and I look forward to those meetings.
Matthew China (Energy Related Business and Service)	For
Joe Saunders (Distributor)	For

TP Member	Vote and/or Rationale
	I voted in favour of the Vote to Recommend the proposed market rule amendments MR-00481-R00-R013 to the IESO Board for approval at its October 18, 2024, meeting. The final alignment for Market Rules and manuals were posted for stakeholder review on June 7, 2024. The comments received from the stakeholder review were shared with the Technical Panel (TP) with a series of TP meetings held in July and August to discuss comments in detail with IESO staff. Due to the complexity of the changes, a number of concerns were raised by TP members, including concerns regarding potential unintended outcomes of the implementation of the market power mitigation (MPM) framework and to mitigate the risk of a material, unintended impact on suppliers. The IESO has committed to the establishment of an MPM working group to address concerns and advise the IESO and TP. The TP has been meeting for many years to discuss the market rule amendments with IESO engaging in significant stakeholder engagement, MPM working groups and TP education sessions. IESO staff and TP agreed that discussions and opportunities for potential amendments would continue through to the May 2025 MRP go-live date.
David Short (IESO)	For

IESO RESPONSES TO TECHNICAL CONFERENCE UNDERTAKINGS

Reference	Undertaking	Response
JT1.1	IESO TO PRODUCE THE DATA AND ANALYSIS USED TO SUPPORT ITS MARKET PARTICIPANT DATA CALCULATIONS, TOGETHER WITH ANY EXPLANATIONS (UNDER ADVISEMENT)	The IESO maintains its refusal. The Applicants are asking the IESO to retrieve and produce a significant amount of data, including confidential market participant bid and offer data, for a document that has been available to its members since September 2022. The Business Case Validation Memo was not included with, or referenced in, the IESO's Descriptive or Responding Evidence and was first introduced into the record by the Applicants at the Technical Conference. If the Applicants believed it was necessary for their expert to review this data, then the Applicants should have requested it at an earlier date. Further, the IESO is refusing to answer the question because it is not a relevant issue in the proceeding and therefore lacks foundation. The application filed by the Applicants does not take issue with the MRP Business Case and Power Advisory did not dispute the MRP Business Case in their report[1] or at the Technical Conference.[2] The IESO's understanding is that the benefits associated with the Amendments are not being contested in this proceeding by the Applicants.
JT1.2	IESO TO CONFIRM THAT THE 1,300 HISTORICAL RESOURCE COMMITMENTS WERE WITHIN THE NQS GROUP (UNDER ADVISEMENT)	The IESO confirms that the 1,300 historical commitments inspected for the MRP Business Case were commitments of NQS resources. The IESO will not undertake an analysis to determine which of those commitments were for the facilities listed in Appendix A of the Power Advisory report.
JT1.3	IESO TO CREATE AND PRODUCE A CHART IDENTIFYING THE MARKET SURVEILLANCE PANEL AND AUDITOR GENERAL OF ONTARIO CRITIQUES AS IT RELATES TO THE REAL-TIME GENERATOR COST GUARANTEE PROGRAM, THE DATE OF THOSE CRITIQUES, TOGETHER WITH THE STEPS THE IESO TOOK TO ADDRESS THOSE CRITIQUES AND THE DATE THAT THOSE STEPS WERE IMPLEMENTED TO ADDRESS THOSE CRITIQUES (REFUSED)	The IESO maintains its refusal. See the response to JT1.10 for copies of the IESO's responses to the MSP's recommendations.

[1] The MRP Business Case is cited in footnotes 3 and 4 of the Power Advisory report without comment.
[2] Technical Conference Day 2 Transcript, p 157, line 25 to p 158, line 5.

Reference	Undertaking	Response
JT1.4	IESO TO PROVIDE ANY INFORMATION OR DATA ON THE NUMBER OF NQS GENERATORS THAT CURRENTLY PARTICIPATE IN THE DAY-AHEAD COMMITMENT PROCESS ON AN INCREMENTAL-ENERGY-OFFER-ONLY BASIS, WITHOUT RELIANCE ON THE GENERATOR COST GUARANTEE PROGRAM (REFUSED)	The IESO maintains its refusal and will not undertake an extensive review of data to respond to this question. The IESO confirms its understanding, as stated at page 7 of its responding evidence, that most NQS resources choose to submit three-part offers because they prefer to receive a cost guarantee.
JT1.5	IESO TO CONSOLIDATE THE INFORMATION IT CONSIDERED INTO EVIDENCE IN THE PROCEEDING THAT WOULD SUPPORT ITS CONCLUSION AND ASSERTION (UNDER ADVISEMENT)	The IESO's statement that ISOs and RTOs in the United States use shorter look-ahead periods because they are less reliant than Ontario on combined cycle gas plants to meet peak demand was based upon Mr. Matsugu's knowledge gained from working in the sector since 2006, including serving as the IESO representative on the ISO/RTO Markets Committee. That ISOs and RTOs in the United States utilize combined cycle gas plants to largely serve base and intermediate load, while generally using less efficient resources to meet peak demand, is common knowledge in the sector. Attached as **Appendix A** is an article published by the U.S. Energy Information Administration which discusses the role of combined-cycle gas plants in the major electricity regions of the United States and highlights their importance in serving base and intermediate load in those regions.
JT1.6	IESO TO CONDUCT A VALIDATION PROCESS RE CMSC	The IESO confirms that only Congestion Management Settlement Credit (CMSC) payments are subject to recovery under the current MPM regime. See MR, Ch 7, App 7.6: Local Market Power and Market Manual 2.12: Treatment of Local Market Power.
JT1.7	IESO TO PROVIDE THE DOLLAR AMOUNT OF EX-ANTE MITIGATION OR EX-POST SETTLEMENT ADJUSTMENTS UNDER THE DAY-AHEAD COMMITMENT PROCESS, UNDER THE CURRENT MARKET POWER MITIGATION REGIME FOR THE 2018 TO 2023 TIME FRAME (REFUSED)	The IESO maintains its refusal.
JT1.8	IESO TO PROVIDE A LIST OF MR. MATSUGU'S PRESENTATIONS, GUEST LECTURES, OR JOURNAL ARTICLES RELEVANT TO MATTERS IN THE PROCEEDING (UNDER ADVISEMENT)	The following are recent examples: • Mr. Matsugu was a member of a panel entitled "Redesigning Markets to Inform and Attract Investment" at the 8th Annual Electricity Workshop | Ivey Energy Policy and Management Centre held on October 15, 2024.

Reference	Undertaking	Response
		• Mr. Matsugu was a guest instructor on designing wholesale markets for the spring/summer 2020 Electricity Markets Course for Ryerson University, Faculty of Engineering and Architectural Science, Department of Electrical and Computer Engineering.
JT1.9	IESO TO PROVIDE A LIST AND CAPACITY OF THE NATURAL GAS GENERATION FACILITIES THAT ARE NON-QUICK START AND ARE NOT PART OF THE NQS GROUP	Please see **Appendix B** for a list of natural gas generating facilities in the province. The IESO has identified whether the facility is listed in Appendix A to the Power Advisory Report and whether it is eligible for PCG/GCG payments.
JT1.10	IESO TO FILE THE FILINGS REQUIRED UNDER SECTION 6.25 OF THE IESO'S LICENCE, SINCE THE FIRST MSP RECOMMENDATIONS, RELATED TO THE ISSUES ADDRESSED BY THE MARKET RENEWAL PROGRAM AND THE MRP AMENDMENTS	Section 6.2.5 was introduced into the IESO's licence in 2013. In accordance with that provision, the IESO filed reports with the OEB for the 2015 to 2024 years. Copies of these reports will be filed by the IESO individually through RESS. As stated in the MSP's State of the Market Report 2023 (published in September 2024), the IESO anticipates that 18 of the previous Panel market design recommendations will be addressed through MRP. The MSP intends to release an MRP pre-deployment report by early 2025 that, amongst other things, will set out its plans to evaluate how MRP has addressed the market inefficiencies raised in past MSP recommendations where the MRP program was identified as the remediation measure for the underlying issue.
JT1.11	IESO TO PROVIDE ITS POSITION ON WHETHER THE MRP AMENDMENTS DISCRIMINATE AGAINST THE NQS GENERATORS, BUT THAT DISCRIMINATION IS JUST; OR THAT THE MRP AMENDMENTS DO NOT DISCRIMINATE AGAIN THE NQS GENERATORS; USING "DISCRIMINATE" IN THE SENSE OF "ECONOMIC DISCRIMINATION", AS DEFINED BY THE OEB (UNDER ADVISEMENT)	The IESO is unclear on the precise nature of the Applicants' unjust discrimination claim in this proceeding. The Applicants have failed to provide a basis for why the grouping of their facilities (listed in Appendix A to the Power Advisory Report) should be treated as a "class of market participants" for the purposes of subsection 33(9) of the *Electricity Act, 1998*. The Applicants' facilities share no unique characteristics that distinguish them from other NQS generation facilities in the province[3] and include facilities that are not eligible for cost guarantee payments.[4] It is the IESO's position that the Applicants' facilities do not constitute a "class of market participants". Further, as Power Advisory's evidence was based on the impact of the Amendments on a fictional proxy generator – the impact of which was then extrapolated to all of the

[3] Technical Conference Day 2 Transcript, p 28, line 2 to p 29, line 6
[4] Technical Conference Day 2 Transcript, p 131, line 25 to p 132, line 14 and p 156, line 2 to 16

Reference	Undertaking	Response
		Applicants' facilities without any regard for their individual characteristics[5] or the possibility that another NQS resource would receive a replacement commitment in place of the proxy generator[6] – the Applicants have not provided any basis for an allegation of unjust discrimination against an individual member of the group. It is not evident to the IESO how the Applicants can advance a claim of unjust discrimination against individual market participants given the evidence that has been filed. In any event, the IESO's position is that the Amendments are not discriminatory against NQS generators, either as a class or against individual market participants. The Amendments account for the unique characteristics of the NQS generators (through the use of mechanisms such as three-part offers and the cost guarantee programs) to place them on an equal footing as other generation resources on a total cost basis in the IESO commitment and scheduling processes. Should the Amendments be found to be discriminatory as against NQS generators, either as a class or as individual market participants, it is the IESO's position that such discrimination is not unjust because the Amendments will improve overall market efficiency as has been acknowledged by Power Advisory.[7] It is the IESO's position that the Applicants have no viable basis upon which to advance an argument that the Amendments are inconsistent with the purposes of the *Electricity Act, 1998* due to their failure to advance any evidence on this point.[8]
JT1.12	IESO TO FILE THE BUSINESS CASE VALIDATION MEMO	A copy of the Business Case Validation Memo dated September 22, 2022 is attached as **Appendix C**.

[5] Technical Conference Day 2 Transcript, p 159, line 5 to p 160, line 26
[6] Technical Conference Day 2 Transcript, p 66, line 28 to p 68, line 11
[7] Technical Conference Day 2 Transcript, p 77, line 23 to p 78, line 6, p 157, line 25 to p 158, line 5.
[8] Technical Conference Day 2 Transcript, p 158, line 14 to p 159, line 4

Appendix B

LIST AND CAPACITY OF THE NATURAL GAS GENERATION FACILITIES

Facility Name	Capacity	Member of NQS Group (as per PA Report Appendix A)	Eligible for PCG/GCG Payments
BIRCHMOUNT CGS	2.6		N
BRIGHTON BEACH CGS	583.75		Y
BUR OAK CGS	3.25		N
CARDINAL POWER CGS	156.34		Y
COCHRANE CGS	22.24		Y
EAST WINDSOR CGS	84	Y	N
EMERALD ENERGY FROM WASTE CGS	10.3		N
GREENFIELD ENERGY CENTRE CGS	1040		Y
GSPC CGS	314		Y
GTAA CGS	90		Y
HALTON HILLS CGS	641.5	Y	Y
KAPUSKASING GS	40		Y
KINGSTON COGEN CGS	110		Y
LAKE SUPERIOR POWER CGS	128		Y
MAITLAND COGEN 1	45.7		Y
NAPANEE GENERATING STATION	900	Y	Y
NELSON CHP II CGS	12		N
NIPIGON GS	20.51		Y
NORTH BAY GS	32.9		Y
NORTHLAND IROQUOIS FALLS CGS	120		Y
NORTHLAND KIRKLAND POWER (SCGT)	28.868		Y
NORTHLAND KIRKLAND LAKE POWER (CCGT)	81		N
OTTAWA HEALTH SCIENCE CENTER CGS	73.7		Y
PORTLAND ENERGY CENTRE CGS	550	Y	Y
SARNIA CGS	444	Y	Y

Appendix B

SITHE GOREWAY CGS	839.1	Y	Y
ST. CLAIR POWER CGS	577	Y	Y
THOROLD GS	241.6	Y	Y
TUNIS GS	36.5		Y
WEST WINDSOR POWER CGS	122.78		Y
WHITBY COGEN CGS	50		Y
WINDSOR TRANSALTA CGS	72.28		Y
YORK ENERGY CENTRE CGS	393	Y	N