**EB-2024-0331**

**ONTARIO ENERGY BOARD**

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

**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**" or "**Applicants**") for Review of Amendments to the Independent Electricity System Operator Market Rules

# INDEPENDENT ELECTRICITY SYSTEM OPERATOR COMPENDIUM FOR CROSS-EXAMINATION OF NQS GENERATION GROUP WITNESSES

January 16, 2025

**STIKEMAN ELLIOTT LLP**
Barristers & Solicitors
5300 Commerce Court West
199 Bay Street
Toronto, Canada M5L 1B9

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Lawyers for the IESO

## INDEX

| TAB # | DOCUMENT |
|---|---|
| 1. | NQS Generation Group Technical Conference Undertaking Responses filed January 13, 2024 |
| 2. | Power Advisory Expert Evidence Report, dated December 18, 2024 |
| 3. | IESO Technical Panel Member Vote and Rationale, dated September 10, 2024 |
| 4. | OEB Monitoring Report on the IESO-Administered Electricity Markets for the period from May 2015 - October 2015, dated November 2016 |
| 5. | Application for Review of the Amendments to the IESO's Market Rules dated November 7, 2024 |

TAB 1

**ONTARIO ENERGY BOARD**

**IN THE MATTER OF** the Ontario Energy Board Act, 1998, S.O. 1998, c. 15 (Sched. B), as amended (the "OEB Act").

**AND IN THE MATTER OF** a Hearing on Application to Review Amendments to the Market Rules made by the Independent Electricity System Operator.

# Technical Conference Undertaking Responses

## Filed: January 13, 2025

# UNDERTAKING JT2.1

**Reference:**
Technical Conference Hearing Transcript (Day 2) page 8 line 6 to 7.

**Undertaking:**
NQS to produce the retainer letter of Mr. Chee-Aloy.

**Response:**
The agreed-to fee cap is commercially sensitive and is not relevant to the matters at issue in this proceeding. NQS is filing the retainer letter of Mr. Chee-Aloy in accordance with the request to redact non-relevant information set out in the cover letter.

**John Vellone**
T: 416-367-6730
jvellone@blg.com

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Bay Adelaide Centre, East Tower
22 Adelaide Street West
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Borden Ladner Gervais

**File No. TBD**

October 30, 2024

**PRIVILEGED AND CONFIDENTIAL**

Jason Chee-Aloy
Managing Director
Power Advisory LLC
Suite 700, P.O. Box 32
Toronto, ON M5J 2H7

Dear Mr. Chee-Aloy:

**Re: Retainer Letter Agreement**
**Assessment of the Market Renewal Program for Ontario Generators**

By way of this letter, Borden Ladner Gervais LLP ("**BLG**" or "**we**") hereby confirms Power Advisory LLC's (the "**Company**" or "**you**") retainer in connection with BLG's legal advice to Northland Power Thorold CoGen L.P., St. Clair Power, L.P., Greenfield Energy Centre, L.P., Capital Power Corporation, Atura Power, and TransAlta Corporation ("**Generation Consortium**") in respect of the Independent Electricity System Operator's ("**IESO**") recent amendments to the Market Rules to implement the Market Renewal Program ("**MRP**"). By signing back a copy of this letter, you agree that this letter contains the agreed-upon terms and conditions of the retainer between BLG and the Company, subject to amendment by written agreement between the parties (the "**Retainer Agreement**").

## 1. NO CONFLICT

You do not have any conflict of interest or other constraints on your ability to provide the services contemplated in this Retainer Agreement.

## 2. SCOPE OF SERVICES AND DELIVERABLES

You have been retained to provide Services to BLG in connection with MRP, in respect of which BLG has been retained to provide legal advice.

The "**Services**" include, but are not limited to, supporting BLG in its assessment of the following areas:

- Review and assessment of the MRP design and amendments to the Market Rules regarding implications for gas-fired generators; and

- Review and assessment of the MRP amendments to the Market Rules relating to associated amendments to contracts, to which gas-fired generators are counterparty with the IESO, and the implications to gas-fired generators.

The project team will consist of the following individuals:

- Jason Chee-Aloy
- Michael Killeavy
- Darryl Yahoda
- Brady Yauch
- Greg Peniuk

In connection with the Services, you have agreed to deliver the following deliverables (the "**Deliverables**"):

- Provide expert report(s) detailing observations, findings, opinions, and recommendations in respect of the MRP design and amendments to the market rules.

Company's work product is to be used only with regard to the Services and not for any other purpose without Company's written approval.

Prior to the submission of any statement describing Company's experience, credentials, or the nature of Company's work and opinions related to this Retainer Agreement, or the publishing of any report authored by Company, Company will be provided a reasonable opportunity to review such statement for accuracy and provide appropriate disclaimers and legends to any such information and materials.

Upon full payment of all amounts due Company in connection with this Retainer Agreement, all rights, title and interest in the Deliverables will become Generation Consortium's sole and exclusive property for Generation Consortium's use in connection with the professional services set forth in this Retainer Agreement, subject to the exceptions set forth below. Company shall retain sole and exclusive ownership of all rights, title and interest in its work papers, proprietary information, processes, methodologies, know-how and software, including such information as existed prior to the delivery of the Services and, to the extent such information is of general application, anything that it may discover, create or develop during provision of the Services ("**Company Property**"). To the extent the Deliverables contain Company Property; Generation Consortium is granted a non-exclusive, non-assignable, royalty-free license to use it in connection with the subject of this Retainer Agreement.

## 3. <u>FEES</u>

By entering into this Retainer Agreement, BLG and the Company acknowledge that the Services will be provided on a time and material basis [redacted]

BLG or the Company may, at any time and from time to time, request in writing additions, deletions, amendments or any other changes to the Services, including to the scope and nature of the Services or the Deliverables (each, a "**Change**"). No Change shall come into effect unless and until it has been approved by BLG and the Company in writing, and once so approved, the applicable Services or Deliverables will be deemed to have been amended in accordance with such Change. For clarity, work subsequent to the delivery of the Deliverables, including future risk assessment support work, will be charged out on a time and material basis, as agreed to by the parties in writing prior to the execution of any such work.

In the event Generation Consortium and/or BLG decide that expert witness services are required, a separate engagement is required.

**4. SCHEDULE**

The Company, BLG and the Generation Consortium will consult with each other on setting a schedule. The Company shall coordinate with BLG and Generation Consortium to update the schedule as required throughout the term of this Retainer Agreement. Unless otherwise agreed to by BLG and the Company in writing, including but not limited through the execution of an approved Change in accordance with the provisions of Section 3, the Retainer Agreement will terminate as soon as the Services and Deliverables are provided and completed by the Company.

**5. ACCOUNTS**

All fees and billings must be approved by both BLG and Generation Consortium. The Company shall invoice BLG monthly for Services rendered. BLG will attach the Company's invoices to BLG's invoices to Generation Consortium for legal services provided by BLG to Generation Consortium in connection with the matters contemplated by this Retainer Agreement. Accordingly, no payment will be made to the Company by BLG until such time as BLG receives payment from Generation Consortium for the same.

Once BLG receives payment from Generation Consortium for Services rendered by the Company during the applicable billing period, BLG will promptly remit same to the Company. In addition, BLG may withhold any payment if there remain outstanding any unresolved issues.

The Company should submit a summary sheet (as described below) only of all accounts to BLG monthly if the amount payable on an assignment exceeds $1,000. Otherwise the Company should submit a summary sheet only of all accounts quarterly or on completion of the assignment within the quarterly period, whichever is earlier. The Company should submit each summary sheet of an account to BLG within 30 days of the earlier of the end of the billing period or completion of the assignment.

The Company will submit all original summary sheets of all accounts by email to John Vellone: jvellone@blg.com. The Company will email all invoices to John Vellone, with a copy to Salvatore.Provvidenza@Northlandpower.com, bnunley@invenergy.com, Brett.Kruse@calpine.com, csutherland@capitalpower.com, Noralyn.Vasquez@aturapower.com, Brian.Heaman@transalta.com.

Due to the confidential nature of the matters contemplated in this Retainer Agreement, BLG requests that the Company submit a detailed account which will include at least the following information for each assignment which is being billed:

a. identification of the assignment by appropriate subject heading for the assignment. Unless specifically agreed otherwise, the Company should provide separate accounts for each assignment;
b. identification of the billing period to which the account relates;
c. an itemised summary of the work that has been undertaken, including a brief description of each service (for example, conference with the instructing BLG, preparation of purchase agreement, etc.), the date on which each service was rendered, the time spent on each service, the individual who performed the service and the billing rate of such individual;
d. a clear line item on the last page of each invoice summarizing all research conducted in the billing period and to indicate whether written results of the research (e.g., reports, memos, opinions) have already been sent to BLG or are attached; and
e. an itemisation and brief description of all expenses incurred during the billing period, with copies of supporting invoices for any expenses in excess of $100, unless BLG indicates that such invoices are not required.

The timely closing of Generation Consortium books at year-end requires the prompt submission of year-end accounts. For accrual purposes, if requested, the Company must calculate anticipated fees and expenses for December and must provide BLG with an estimate of these charges by December 15, unless the December charges will total less than $1,000. Following the completion of the calendar year, the Company is required to specify on all invoices any fees or costs that are for work that was delivered in a previous calendar year.

BLG will also reimburse the Company for all reasonable out-of-pocket expenses incurred on behalf of BLG, subject to Section 6 of this Retainer Agreement.

BLG does not pay premiums or bonuses based on results, unless otherwise agreed in writing.

## 6. OTHER RULES ON FEES AND EXPENSES

a. The Company may bill BLG for travel expenses only in accordance with Generation Consortium's Standard Form Business Expense Schedule provided by Generation Consortium to BLG and the Company as the same may be amended, supplemented or replaced from time to time. The Company may not bill BLG for any time away from the office which is not spent performing Services for BLG and Generation Consortium.

b. The Company may bill BLG for photocopying at a rate of no more than $0.10 per page. If it is anticipated that the photocopying expenses for a particular matter will exceed $500, please advise BLG accordingly so that we may consider whether the copying services should be performed by a third party service provider.

c. The Company may bill BLG for long distance phone calls at no more than the Company's internal costs for those calls. If requested, the Company will include with any applicable account provided to BLG, the per minute charge applied to each long distance call and the date and length of each call.

d. The Company may not bill BLG for the transmission or receipt of faxes. Whenever possible, e-mail is preferred.

e. The Company may not bill BLG for routine secretarial work or office administration, including charges for "opening a file", software licenses, system application charges, word processing, printer charges, research search fees, local telephone expenses or office supplies.

f. The Company may not bill BLG for overtime of administrative staff, unless BLG has consented to such billings in advance.

g. The Company may not bill BLG for time spent preparing or reviewing proposals, accounts or budgets.

h. The Company may not bill BLG for food or refreshments provided to BLG representative at meetings in the office of the Company.

i. The Company may not bill BLG for meals provided to the Company's employees, contractors or agents.

## 7. CONFIDENTIALITY & PRIVILEGE

Unless we advise you otherwise, the information, documents and other materials that you will receive from BLG and Generation Consortium are proprietary and confidential (the "**Confidential Information**"). You hereby acknowledge the privileged and confidential nature of the Confidential Information and the damage that could result if the Confidential Information is disclosed to any third party. The Confidential Information is only being provided for the purpose of delivering the Services and Deliverables, and it would not otherwise be disclosed to you. In connection with your retainer, you undertake, subject to applicable law or court order, to preserve the confidentiality of any Confidential Information, received from BLG, or Generation Consortium or its agents in the course of the retainer.

From the outset of this retainer, our communications will be privileged (in that they will remain confidential). Notwithstanding the foregoing, Generation Consortium reserves the right, in its sole and absolute discretion, and without notice to the Company, to unilaterally waive privilege over any communications or Deliverables produced in connection with the matters contemplated by this Retainer Agreement.

## 8. TERMINATION

Either party may terminate this Retainer Agreement at any time on thirty (30) days' prior written notice to the other party. BLG agrees to pay for work performed up to the effective date of termination, subject to the terms of Section 5. Upon BLG's written request, you shall return to BLG and delete any and all electronic copies you may have of all documents and materials in your possession relating to this Retainer Agreement, including all Confidential Information and the Deliverables, whether completed or not; provided, that, Company may retain a copy of its reports and work papers.

**9. LIMITATION OF LIABILITY**

To the extent that BLG asks the Company to reach conclusions or form opinions, the Company is obligated to give BLG its best independent judgement without regard to the impact that such conclusions or opinions might have. [redacted]

The preparation of work product by the Company is an evolving process during which the Company's analysis is focused and refined as its research and document review proceeds and as information emerges under this Retainer Agreement. Preliminary conclusions, superseded drafts, worklists and irrelevant data are not a part of and will not be recorded in Company's final work product. Such documents may be provided on a routine basis as work tasks are completed. Circumstances may arise that require the retention of such drafts or other interim documents. The Company understands that BLG will provide the Company with instructions regarding document retention and production procedures that BLG expects it to follow.

[redacted]

## 10. ROLE AND DUTY OF AN EXPERT

Rule 13A of the OEB *Rules of Practice and Procedure* (the "**Rules**") provides that an expert shall assist the Board impartially by giving evidence that is fair and objective.[1] Additionally, an expert may give evidence in a proceeding only on issues that are relevant to the expert's area of expertise.

By entering into this Retainer Agreement, you acknowledge and agree that you have received a copy of Rule 13A of the Rules concerning expert evidence, and agree to accept the responsibilities that are or may be imposed on you by that rule with respect to testimony before the OEB.

You must attest to your understanding of and compliance with the foregoing in Form A (Acknowledgement of Expert's Duty) that is appended to the Rules.[2] It is important that you understand your duties as an expert. Please contact us if you have any questions or require further information. Otherwise, please return this Form A to us when you deliver your report.

## 11. ENTIRE AGREEMENT

This Retainer Agreement constitutes the complete agreement between BLG and the Company with respect to the subject matter hereof and supersedes any and all prior agreements and understandings. This Retainer Agreement may be amended only in a writing that refers to this Retainer Agreement and is signed by both parties. Where a conflict exists between the SOW and this Retainer Agreement, this Retainer Agreement shall prevail.

*[signature page follows]*

[1] https://www.oeb.ca/sites/default/files/uploads/documents/regulatorycodes/2024-03/OEB_Rules-Practice-and-Procedure_20240306.pdf

[2] A copy of this form is found here: https://www.oeb.ca/oeb/_Documents/Regulatory/Rules_Form-A_Experts_Duty.pdf

Yours truly,

**BORDEN LADNER GERVAIS LLP**

[redacted]

John Vellone

JV/

**Power Advisory LLC**

[redacted]

Per:

Name: Jason Chee-Aloy
Title: Managing Director
Date: October 30, 2024

# UNDERTAKING JT2.2

**Reference:**
Technical Conference Hearing Transcript (Day 2) page 20 line 5 to 11.

**Undertaking:**

(A) NQS Group to confirm whether the team met with the IESO and make presentations to the IESO that are also covered in your independent expert report in this case (Refused).

(B) NQS Group to confirm whether witnesses continue to be engaged by some or all of the Applicants in respect of contract amendment negotiations with the IESO (Refused).

**Response:**
Refused

# UNDERTAKING JT2.3

**Reference:**
Technical Conference Hearing Transcript (Day 2) page 90 line 20 to 22.

**Undertaking:**
NQS to file references to pre-dispatch and real-time tables from market surveillance panel reports.

**Response:**

The following data was pulled from the most recent Market Surveillance Panel (MSP) reports that contained the relevant data. The most recent MSP reports – State of the Market for 2022 and 2023 – no longer contain price-setting tables.

https://www.oeb.ca/sites/default/files/msp-monitoring-report-202303.pdf

*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% | - |

https://www.oeb.ca/sites/default/files/msp-monitoring-report-202203.pdf

Table A-3: Share of Resource Type Setting the Real-Time MCP, 3 Periods[56]

| Resource Share (%) | Winter 2019/20 | Summer 2020 | Winter 2020/21 |
|---|---|---|---|
| Hydro | 41.8% | 38.5% | 48.7% |
| Wind | 24.1% | 21.1% | 19.3% |
| Gas | 32.5% | 38.2% | 30.8% |
| Nuclear | 0.02% | 0.8% | 0% |
| Solar | 0.01% | 0.09% | 0% |
| Biofuel | 1.7% | 1.2% | 1.3% |

Table A-4: Share of Resource Type Setting the Pre-Dispatch MCP, 3 Periods[58]

| Resource Share (%) | Winter 2019/20 | Summer 2020 | Winter 2020/21 |
|---|---|---|---|
| Hydro | 19.7% | 22.2% | 18.8% |
| Wind | 11.7% | 10.5% | 8.2% |
| Gas | 21.4% | 28.8% | 26.8% |
| Nuclear | 0% | 0.3% | 0% |
| Solar | 0.02% | 0.2% | 0.04% |
| Biofuel | 0.9% | 0.8% | 0.8% |
| Imports | 20.9% | 12% | 27.5% |
| Exports | 25.2% | 25.2% | 17.8% |
| Loads | 0.08% | 0.08% | 0.2% |

https://www.oeb.ca/sites/default/files/msp-monitoring-report-202108.pdf

*Table A-4: Share of Resource Type Setting the Pre-Dispatch MCP, 3 Periods*

| Resource Share (%) | Summer 2019 | Winter 2019/20 | Summer 2020 |
|---|---|---|---|
| Hydro | 18% | 20% | 22% |
| Wind | 18% | 12% | 10% |
| Gas | 23% | 21% | 29% |
| Nuclear | **5%** | 0% | **0.3%** |
| Solar | 1% | 0.02% | 0.2% |
| Biofuel | 0.5% | 1% | 1% |
| Imports | 15% | 21% | 12% |
| Exports | 19% | 25% | 25% |

*Table A-4 presents the share of intervals in which each resource type, imports and exports set the Pre-Dispatch MCP in the Summer 2019 Period, the Winter 2019/20 Period and the Summer 2020 Period.*

*Table A-3: Share of Resource Type Setting the Real-Time MCP, 3 Periods*

| Resource Share (%) | Summer 2019 | Winter 2019/20 | Summer 2020 |
|---|---|---|---|
| Hydro | 34% | 42% | 39% |
| Wind | 29% | 24% | 21% |
| Gas | 28% | 32% | 38% |
| Nuclear | **7.3%** | 0.02% | **0.8%** |
| Solar | 0.8% | 0.01% | 0.09% |
| Biofuel | 0.7% | 1.6% | 1.2% |

*Table A-3 presents the share of intervals in which each resource type set the real-time MCP in the Summer 2019 Period, the Winter 2019/20 Period and the Summer 2020 Period.*[117]

# UNDERTAKING JT2.4

**Reference:**
Technical Conference Hearing Transcript (Day 2) page 143 line 24 to 26.

**Undertaking:**
NQS to confirm whether the York Energy Centre and East Windsor Cogeneration facility earn RT-GCG revenues.

**Response:**

No. Both the York Energy Centre and the East Windsor Cogeneration facilities do not currently participate in the RT-GCG program.

# UNDERTAKING JT2.5

**Reference:**
Technical Conference Hearing Transcript (Day 2) page 147 line 1 to 3.

**Undertaking:**
NQS to file a live excel version showing the calculations of the data in figures 19, 20, and 22 in the power advisory report (Refused).

**Response:**
Refused

# UNDERTAKING JT2.6

**Reference:**
Technical Conference Hearing Transcript (Day 2) page 155 line 28 to page 156 line 1.

**Undertaking:**
NQS to ask Power Advisory to confirm the list of facilities in its report.

**Response:**

The list of facilities used in the report and the financial impact analysis are listed in Appendix A.

# TAB 2

Expert Evidence in Appeal

December 18, 2024

With instructions from
Borden Ladner Gervais (BLG) LLP

Prepared by
Brady Yauch, Michael Killeavy, and Jason Chee-Aloy
Power Advisory LLC

TABLE OF CONTENTS

# 1. Introduction and Overview of Report

1. Power Advisory LLC ("Power Advisory") was retained on behalf of Borden Ladner Gervais LLP ("BLG") to provide expert evidence regarding the financial harm facing a group of Non-Quick Start Generators[1] ("NQS Generation Group" or "NQS Generators"), a subset of natural gas-fired generators, resulting from amendments to the Market Rules ("MRP Amendments"). The MRP Amendments were approved by the Independent Electricity System Operator ("IESO") Board of Directors on October 18, 2024. The MRP Amendments represent a significant re-design of the IESO-Administered Markets ("IAM") (i.e., Ontario's wholesale electricity market) that defines the IESO's Market Renewal Program ("MRP").

2. Given the highly complex physical and financial design of the IAM, the information and examples in this report have been simplified where possible. The evidence in this report provides a detailed review and analysis on the financial harm the MRP Amendments will have on the NQS Generators. The financial harm imposed on the NQS Generators is not imposed to similar extent – or at all – on other supply resources (e.g., hydroelectric, nuclear, wind and solar generators, etc.) and Market Participants ("MPs"). To Power Advisory's knowledge, the IESO has not released an extensive analysis to suggest it has considered the financial impact of the MRP Amendments on different supply resources, including NQS Generators.

3. Section 2 of this report provides a high-level description of Power Advisory, as well as the authors, Brady Yauch, Michael Killeavy, and Jason Chee-Aloy.

4. Section 3 provides a summary of the evidence and Power Advisory's findings relating to financial harm that will be incurred by NQS Generators from the implementation of the MRP Amendments.

5. Section 4 provides a Glossary of Terms used throughout this report.

6. Section 5 provides a background of MRP, including its scope and objectives. This section also provides a detailed review of the participation of NQS Generators under the current IAM and future IAM post MRP implementation. This section also includes a detailed review and breakdown of various market design components in the IAM and their implications on the commitment, dispatch, and financial settlement for NQS Generators.

7. Section 6 provides a detailed analysis on the financial harm that the MRP Amendments will impose on the NQS Generators. This section also includes an overview of the potential financial harm – or lack thereof – facing other MPs from the MRP Amendments.

8. Section 7 reviews implications of the MRP Amendments on contracts to which the NQS Generators are counterparty to with the IESO. While the financial harm facing NQS Generators is a result of the MRP Amendments, Ontario's unique "hybrid" market – that

[1] Capital Power Corporation, Thorold CoGen L.P., Portlands Energy Centre L.P., dba Atura Power, St. Clair Power L.P., TransAlta (SC) L.P.

incorporates extensive contracting and rate regulation for nearly all supply resources (e.g., generators, storage) – requires a holistic view of the IAM design, the Market Rules, and the interaction of contracts with the IAM. This section will also provide historical context of previous disputes between contracted generators and various IAM market design decisions undertaken by the IESO including associated amendments to the Market Rules.

9. Finally, Section 8 provides an overview of the importance of NQS Generators to maintaining Ontario's power system reliability and achieving broader policy objectives established by the Ontario government. In multiple ways, the Ontario government has highlighted the importance of the NQS Generators in meeting its electricity and non-electricity (e.g., economic development) policy objectives. The MRP Amendments counteract this policy support by introducing financial harm that is not being equally applied to other MPs within the IAM or to potential future MPs through current electricity supply procurement processes being undertaken by the IESO to contract for needed supply resources (e.g., re-contracting operating generators, contracting new generation and storage projects). Additionally, the IESO has not taken steps to address the financial harm imposed by the MRP Amendments through effective amendments to NQS Generators' contracts.

## 2. Power Advisory and Authors' Background

10. Power Advisory is an electricity management consulting firm with offices in Toronto, Calgary, and Boston. Power Advisory has expertise in areas including wholesale electricity market design, electricity supply procurement and contracting, electricity supply project development, regulatory frameworks, power system planning, electricity price forecasting, electricity tariff rate design, among other areas of the electricity sector. Power Advisory staff includes economists, engineers, power system planners, and commercial management specialists. Power Advisory is involved in jurisdictions across North America, with a particular focus on Canada – particularly Ontario and Alberta – and the Northeast U.S. Many of Power Advisory's staff have worked for the Independent System Operators ("ISOs") and energy regulators in Ontario or Alberta.

11. Brady Yauch is the Senior Manager of Markets and Regulatory Affairs at Power Advisory. His experience includes working at the IESO with a focus on assessing wholesale market design. He has provided expert evidence as part of arbitrations, as well as provided expert evidence before the Ontario Energy Board ("OEB"). He holds an M.A. in Economics and more than 13 years experience in the sector. Mr. Yauch oversees Power Advisory's electricity price forecasts in multiple jurisdictions, including Ontario and New York, among others. He also provides detailed economic and regulatory analysis for a variety of clients regarding investments and strategic decisions related to electricity markets. Those clients include MPs in jurisdictions that operate within wholesale electricity markets and rate regulated vertically integrated utilities. He has been retained by Independent Power Producers, financial firms (e.g., lenders), and government agencies for strategic, financial, and policy advice regarding wholesale electricity market design. He has actively participated in wholesale market design changes in Ontario over the past decade and more recently has modelled the financial impact of wholesale market design changes, including MRP design, for a variety of clients in Ontario and elsewhere, relying on in-depth knowledge of both the regulatory and market structure and design of Ontario's electricity sector. Mr. Yauch is an expert in energy markets, wholesale market design, and energy policy.

12. Michael Killeavy is the Commercial Director and joined Power Advisory in April 2018. He has been involved in a wide variety of commercial engagements for generators in Ontario. Before joining Power Advisory, he was the Director, Contract Management at the Ontario Power Authority ("OPA") and the IESO. Mr. Killeavy was responsible for the approximate 30,000 MW portfolio of OPA/IESO generation contracts, as well as the Energy Support programs, and a staff of 50 professionals and operating budget of $3.5 million. He is an experienced commercial negotiator having negotiated contracts and amendments to contracts for Ontario's gas-fired generators, including the relocation of two large gas-fired generation projects in Ontario. Since joining Power Advisory, he has undertaken many market and contract revenue earning potential assessments for generators in Ontario, including dispatch and financial modelling for gas-fired generation projects. Mr. Killeavy has a B.A. Sc. from the University of Toronto and M. Eng. degree in civil engineering from McMaster University, an M.B.A. from McMaster

University, and an Honours LL.B. from Nottingham Law School in the UK. Mr. Killeavy is an expert in electricity contract design and wholesale energy markets.

13. Jason Chee-Aloy is the Managing Director of Power Advisory, and a senior electricity market and electricity policy expert based in Toronto. He has over 25 years of experience in competitive and regulated energy markets. Mr. Chee-Aloy has acted for multiple clients with business and policy interests across Canada and the U.S., within areas of wholesale electricity market design, procurement and contracting for electricity supply resources, generation development and investments, transmission and distribution development, energy storage development, market assessment and intelligence, business strategy, energy policy development, and regulatory and litigation support. Prior to joining Power Advisory, he was the Director of Generation Procurement at the OPA where he led all procurement and contracting for generation and demand response projects resulting in over $15 billion in electricity supply investments. Prior to the OPA, Mr. Chee-Aloy led resource adequacy, market development, and market surveillance initiatives for the IESO, and was part of the team that implemented Ontario's wholesale electricity market in May 2002. Mr. Chee-Aloy is a member of the Boards of the Ontario Energy Association, the Canadian Renewable Energy Association, and the National Electricity Roundtable. In 2022, Mr. Chee-Aloy was awarded with the Clean50 award for 2023, as one of Canada's exceptional contributors to the clean economy. He was selected as the Hedley Palmer award recipient from the Association of Power Producers of Ontario in 2019 as a leading contributor to the independent power industry, and in 2009 he was awarded with the Canadian Solar Industries Association Leader of the Year award. Mr. Chee-Aloy holds an M.A. in Economics with a focus on financial markets and graduated from York University and the University of Toronto.

14. The curriculum vitae ("CV") of all the authors are attached as Appendices.

## 3. Summary of Evidence from Power Advisory

15. The IESO's MRP Amendments represent a significant overhaul of the IAM design and Market Rules. The MRP Amendments, among other changes, will introduce new calculation engines and settlement mechanisms that will determine commitment, dispatch, and settlement for NQS Generators and supply resources owned and operated by other MPs within the IAM. Notably, the MRP Amendments will result in the introduction of Locational Marginal Prices ("LMPs"), a Day-Ahead Market ("DAM"), new commitment programs for NQS Generators, and an extensive Market Power Mitigation ("MPM") framework, among other changes.

16. The MRP Amendments will significantly change the participation, commitment, dispatch, and settlement of NQS Generators. The overall result of these changes, from a financial perspective, will be negative for NQS Generators. The NQS Generators will – holding all variables and factors constant – be committed and dispatched less within the IAM under the MRP Amendments. This will result in less wholesale market revenues compared to the current Market Rules. Further, based on the calculation of certain IAM-related payments under the MRP Amendments, this will further lessen wholesale market revenues for NQS Generators. These negative financial impacts will not be offset through commensurate amendments to the contracts that NQS Generators hold with the IESO. This report provides a detailed and step-by-step analysis on the commitment, dispatch, and financial settlement impacts to NQS Generators that will show the resulting negative financial impacts. Our analysis includes assessment of the MRP calculation engines and guarantee programs from the day-ahead ("DA") to real-time ("RT") timeframes.

17. Based on a historical impact analysis, the average negative financial impact to a typical NQS Generator is more than $3.5 million annually or $21 million in total over the 2018 to 2023 timeframe. This financial impact is based on a comparison between commitment, dispatch, and settlement within the IAM, using the current Market Rules compared to the MRP Amendments and includes a number of assumptions to isolate the financial impact. Additionally, the MRP Amendments result in a $38 million negative financial impact resulting from of a reduction in commitment of the proxy NQS Generator in the IAM over the six-year time frame. This impact is not accounted for in the "deemed" dispatch settlement structure contained in the contracts the NQS Generators hold with the IESO.

18. The values above are based on one, 600 MW proxy NQS Generator. As such, the market impact of the MRP Amendments across the entire NQS Generation Group would be more than $140 million over the 6-year time frame, or more than $23 million annually. From a contract perspective, the impact would $250 million over the 2018 – 2023 time frame if applied to all of the MWs owned by the NQS Generation Group subject to the deemed dispatch contract and NQS participation in the IAM.

19. Other MPs with different supply resources in the IAM will not face a similar level of financial risk as the NQS Generators will, based on the MRP Amendments. These supply resources will either have the exclusive privilege of making use of additional operational constraints that they can impose on the MRP's calculation engines (as

applicable to specific hydroelectric generators) – without the threat of mitigation that applies to every operational and financial parameter for NQS Generators – or will have their contracts amended to account for the financial harms imposed by the MRP Amendments (as applicable to wind and solar generators).

20. The Appendix provides a backward-looking quantitative analysis of the MRP Amendments and their financial impacts to a proxy NQS Generator. To Power Advisory's knowledge, the IESO has not provided analysis on the financial impacts of the MRP Amendments on NQS Generators or other supply resources. Further, to assist such financial impact analysis, to Power Advisory's knowledge, the IESO has not provided quantitative analysis regarding market design options that compared how NQS Generators will be committed and settled under the MRP Amendments to how NQS Generators are committed and settled within other Canadian and U.S. wholesale electricity markets. The intent of our analysis was to highlight the financial impacts of the MRP Amendments on NQS Generators compared to the current Market Rules.

21. While the associated contracts that the NQS Generators hold with the IESO are not the primary focus of this report, the unique nature of Ontario's "hybrid" market – the interconnection of contracts and rate regulation with a wholesale electricity market – cannot be ignored. The IESO itself repeatedly highlighted that it planned to address contract amendments in conjunction with the MRP Amendments. Therefore, the IESO undertook a detailed contract amendment process with multiple MPs throughout the MRP stakeholder engagement process over the course of years through to the present. In addition to contracted generators, Ontario Power Generation ("OPG") has specifically stated that certain areas of its regulated payments overseen by the OEB need to be updated as a result of MRP.[2] The interconnection of the wholesale electricity market and contracts in Ontario – and any financial impacts between the two – cannot be fully separated and have not been done so for all other supply resources, nor have they been viewed in isolation in the past. The negative financial impacts for NQS Generators, resulting from the MRP Amendments, has not, as of the filing of this report, been sufficiently addressed through contract amendments or other mechanisms. While the MRP Amendments may, according to the IESO improve the overall economic efficiency of the IAM, they also introduce financial harm, which has been addressed for some supply resources, but not for NQS Generators.

22. Ontario is facing significant energy and capacity supply shortfalls over the next two decades. This will clearly require the ongoing operation of NQS Generators to help maintain power system reliability. Therefore, the importance of understanding the negative financial impacts of the MRP Amendments on NQS Generators is vital in maintaining overall power system reliability and ensuring the long-term viability of electricity supply investments that is paramount to Ontario's electricity system and economic wealth.

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[2] See: https://files.opg.com/wp-content/uploads/2024/02/M1-1-1-Market-Renewal-Program_240202_142732.pdf

## 4. Glossary of Terms

23. The following table provides a list of terms and acronyms that will be used throughout this report.

| | |
|---|---|
| ADE | Availability Declaration Envelope |
| ANR | Actual Net Revenue |
| APO | Annual Planning Outlook |
| BNGS | Bruce Nuclear Generation Station |
| CMSC | Congestion Management Settlement Credit |
| DA-GOG | Day-Ahead Generation Offer Guarantee |
| DA-PCG | Day-Ahead Production Guarantee |
| DACE | Day-Ahead Calculation Engine |
| DACP | Day-Ahead Commitment Process |
| DAM | Day-Ahead Market |
| DNGS | Darlington Nuclear Generation Station |
| ERUC | Enhanced Real-Time Commitment |
| HOEP | Hourly Ontario Energy Price |
| IAM | IESO-Administered Market |
| ICA | Incremental Capacity Auction |
| IESO | Independent Electricity System Operator |
| INR | Imputed Net Revenue |
| ISO | Independent System Operator |
| LAP | Look-Ahead Period |
| LMP | Locational Marginal Price |
| LTEP | Long-Term Energy Plan |
| MCP | Market Clearing Price |
| MGBRT | Minimum Generation Block Run-Time |
| MLP | Minimum Loading Point |
| MP | Market Participant |
| MPM | Market Power Mitigation |
| MRP | Market Renewal Program |
| MWP | Make-Whole Payments |
| NQS | Non-Quick Start Generator |
| NRR | Net Revenue Requirement |
| OEB | Ontario Energy Board |
| OPA | Ontario Power Authority |
| OPG | Ontario Power Generation |
| OR | Operating Reserve |
| PD | Pre-Dispatch |
| PNGS | Pickering Nuclear Generation Station |
| RT | Real-Time |
| RT-GCG | Real-Time Generation Cost Guarantee |
| RT-GOG | Real-Time Generation Offer Guarantee |
| RTM | Real-Time Market |
| RTO | Regional Transmission Operators |
| SNL | Speed No-Load |
| SSM | Single Schedule Market |

## 5. MRP Background and NQS Generators

24. The MRP is the most significant re-design of the IAM since it was introduced in May 2002 ("Market Opening"). It includes numerous market design reforms to address certain components of the IAM that have been in place since Market Opening.[3] In many respects, the overall design of MRP borrows heavily from the current market design of numerous U.S. wholesale electricity markets administered by Regional Transmission Operators ("RTOs") and ISOs – all of which have been in operation for decades. Nonetheless, the IAM's unique "hybrid" structure – that combines out-of-market payments through contracting and rate regulation to nearly all MPs who own and operate supply resources (e.g., generators, storage, etc.) – has required amendments to various contracts and regulatory mechanisms to account for market design changes included in the MRP Amendments.[4] As discussed below, MRP – of which the MRP Amendments are an integral step towards MRP's planned implementation in May 2025 – will require MPs to participate differently in the IAM, resulting in different dispatch, financial, and settlement outcomes than the current IAM.

### 5.1 *MRP Scope and Objectives*

25. The MRP was launched in 2016 and includes several distinct and central design components.[5] The three main components of MRP are:

   a. ***Single Schedule Market ("SSM")*** – MRP will replace the current two-schedule market with a SSM that will produce LMPs across all nodes on the transmission system within the IAM and eliminate payments of Congestion Management Settlement Credits ("CMSCs"). The rationale of moving from the existing two-schedule market to a SSM with LMPs and the elimination of CMSCs is addressed below. The SSM also includes an extensive MPM framework that is not present in the current IAM.

   b. ***DAM*** – MRP will implement a financially-binding DAM that will introduce a two-settlement system between DA and RT. According to the IESO, the DAM is intended to provide greater "operational certainty" for supply resources (e.g., generators, storage, etc.) operated by MPs and allow the IESO to "only commit resources required to meet system needs."[6] The DAM will incorporate dispatch data in the form of three-part offers from NQS Generators and multi-hour optimization for commitment.

   c. ***Enhanced Real-Time Commitment ("ERUC")*** – The introduction of three-part offers – which includes incremental energy, start-up, and speed no-load ("SNL")

[3] Market Renewal Energy Stream Business Case, October 22, 2019, page 8: https://www.ieso.ca/-/media/Files/IESO/Document-Library/market-renewal/MRP-Energy-Stream-Business-Case-2019.pdf
[4] See the IESO's approach to amending contracts as a result of the MRP Amendments: https://www.ieso.ca/Market-Renewal/Background/MRP-implications-to-electricity-supply-contracts
[5] Market Renewal Energy Stream Business Case, October 22, 2019, page 9
[6] Day-Ahead Market High Level Design, August 2019, page 2: https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/dam/DAM-High-Level-Design-Aug2019.pdf

costs – for NQS Generators in the Pre-Dispatch ("PD") timeframe and optimization of commitment decisions over multiple contiguous hours, among other changes.

26. As noted, MRP was introduced to address certain components within the IAM that have been in place since Market Opening. While the IESO has made amendments to the Market Rules and other modifications to the IAM over the last two decades, many of the primary design features of the IAM have remained largely the same. In justifying the need for MRP, the IESO's Benefits Case noted that the current IAM contains a number of "limitations" and that many of these limitations are long-standing.[7] The MRP was also intended to address some of the "complexities" of the current IAM design that had, according to the IESO, "become a barrier to evolving the market to cost-effectively meet shifts in market fundamentals and public policy goals."[8]

27. While the goal of MRP was to address some of the longstanding components of the current IAM, it focused on a number of key issues: i) the two-schedule system (including a uniform market clearing price across the province that ignored physical constraints on the grid), ii) the lack of a financially-binding DAM, and iii) commitment programs for NQS Generators that were not fully optimized across multiple hours and fully inclusive of the total cost of committing NQS Generators. The three components that are most relevant in the context of financial harm for the NQS Generation Group – as analyzed in more detail later in this report – are: i) the elimination of the two-schedule system, ii) the introduction of new commitment logic in the DAM and ERUC, iii) the elimination of current cost guarantee programs and associated payments. Nearly all of these changes will primarily impact NQS Generators, while having limited to no financial impact on other supply resources.

### 5.2 *Understanding the Current Design of the IAM*

28. To understand why the move to LMPs and elimination of payments of CMSCs was included in MRP, it is important to understand the current design of the IAM. The two-schedule system includes two modes: i) one that determines market clearing prices and market schedules, and ii) one that determines physical dispatch. These are known as the unconstrained mode (i.e., unconstrained or market schedule) and the constrained mode (i.e., constrained or dispatched schedule), respectively. The following paragraphs provide a high-level description of the two modes to provide an understanding of how the two-schedule system operates, and why one of MRP's main purposes was to eliminate it, along with the out-of-market payments associated with it (e.g., CMSCs).

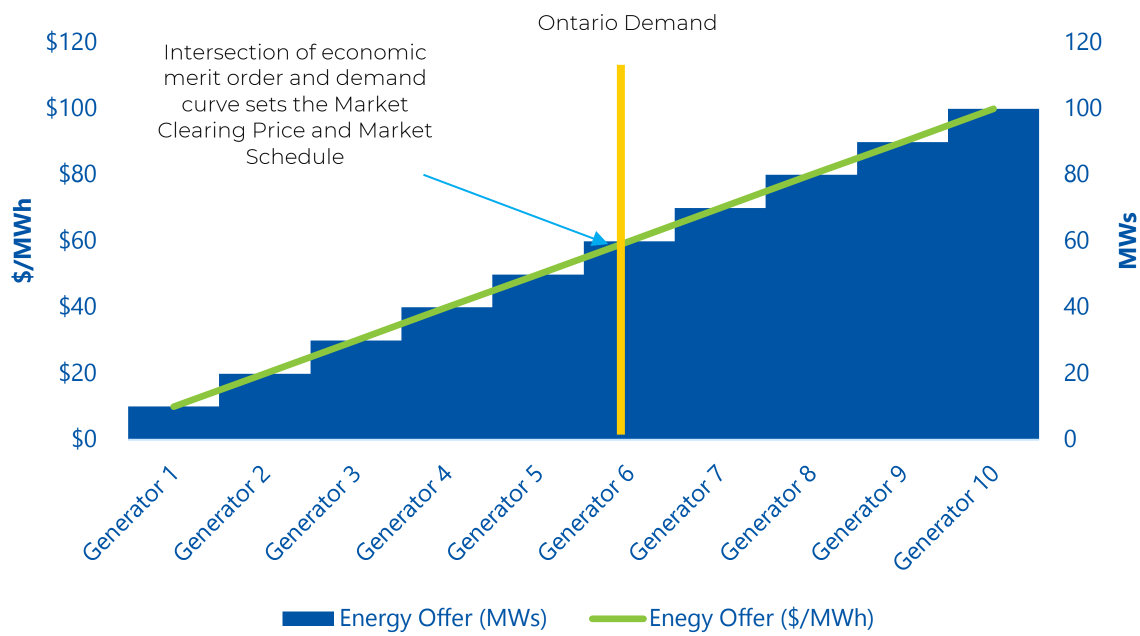
29. The unconstrained mode produces wholesale "market" prices and market schedules by assuming there are no transmission constraints, transmission losses, or other

[7] The Future of Ontario's Electricity Market: A Benefits Case Assessment of the Market Renewal Project, April 20, 2017: https://www.ieso.ca/-/media/Files/IESO/Document-Library/market-renewal/Benefits-Case-Assessment-Market-Renewal-Project-Clean-20170420.pdf

[8] The Future of Ontario's Electricity Market: A Benefits Case Assessment of the Market Renewal Project, April 20, 2017, page i-iii

physical constraints on the grid. In the unconstrained algorithm, all of the bids from demand resources and offers from supply resources operated by MPs – including financial (i.e., incremental energy price) and physical (i.e., number of MWs) components – are stacked from lowest cost to highest cost. The stack of energy offers is known as the economic merit order. The economic merit order is then matched against total demand in the IAM. The convergence of the two results in both a market price and market schedule for all supply resources operated by MPs. The market schedule is a notional schedule based on economics and does not represent the actual physical schedule MPs are to follow.

**Figure 1 Price-setting in the IAM**




30. The constrained mode incorporates the physical characteristics of the electricity grid and supply resources (e.g., generators, storage, etc.) in setting schedules. The primary physical considerations included in the constrained mode compared to the unconstrained mode are transmission losses, transmission constraints, security limits, and other physical attributes of MPs, particularly NQS Generators and hydroelectric supply resources. The outputs from the constrained mode include the dispatch schedules, which represent the actual physical schedule MPs are to follow, and "shadow" prices. Shadow prices represent the price of injecting energy at every node and are representative only, as they are not incorporated in settlements – the IESO does not consider them "settlement ready".[9]

31. Market schedules and dispatch schedules often diverge. For example, an MP's supply resource energy offers may be uneconomic in the market schedule, but it may be committed in the dispatch schedule due to various constraints on the electricity grid. To ensure the MP follows dispatch, the IESO will provide payment of CMSCs to make this resource financially whole and ensure they do not suffer an operating loss by

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[9] See: https://www.ieso.ca/-/media/Files/IESO/Document-Library/training/WB-Intro-Ontario-Physical-Markets.ashx

following their dispatch schedule. If, for example, the wholesale market price (called the Market Clearing Price ("MCP")), is $10/MWh and the energy offer from an MP is $25/MWh but it is instructed to generate in the dispatch schedule – even though it is uneconomic based on the market schedule – the supply resource will receive a CMSC payment of $15/MWh ($25/MWh – $10/MWh) to keep it whole to its $25/MWh energy offer.

32. The introduction of the SSM and associated LMPs as part of the MRP Amendments eliminates the payment of CMSCs that account for differences between the market schedule and physical dispatch schedule. As a result, the LMPs of energy consumed and supplied at every node on the grid will be priced based on actual conditions (i.e., constraints) on the grid – in contrast to the current IAM where the uniform price and associated payments of CMSCs do not provide an accurate price signal to MPs (i.e., generators, storage, loads, etc.). As discussed elsewhere, the SSM will also include a financially-binding DAM (the second significant component of MRP) that will replace the current DA process (which does not include financial obligations)

33. The ERUC component and redesign of commitment logic and programs in the IAM included in the MRP Amendments is also relevant to understanding MRP and the potential for financial harm to NQS Generators. Some MPs, such as gas-fired generators, have specific operational characteristics and constraints that need to be considered when they are committed and dispatched to provide energy or operating reserve ("OR") in the IAM. Gas-fired generators, for example, must operate for a certain number of hours and cannot operate below a certain energy production level for technical reasons. Many gas-fired generators also require a certain number of hours to come online and supply energy. Notably, the need for more than an hour or "lead time" to bring a generation unit online is the primary reason NQS Generators are known as "non-quick start" generators.

34. There are three operational considerations related to NQS Generators that are vital to understanding commitment programs in the IAM and the financial impacts of the MRP Amendments. The main operational constraints relevant to this report are:

a. *Minimum Generation Block Run-Time ("MGBRT")* – The number of hours that an NQS Generator must technically operate at or above its Minimum Loading Point in order to operate safely.

b. *Minimum Loading Point ("MLP")* – The minimum amount of energy (i.e., its MLP) that an NQS Generator must provide in each hour throughout its MGBRT to operate safely in accordance with the technical capabilities of the generation units.

c. *Lead Time* – The number of hours it takes for an NQS Generator to reach its MLP from an offline state.

35. NQS Generators require both a certain amount of lead time and costs to bring their generation units online. While wholesale energy prices can recover some (or all) of these costs, there may be many instances when revenues earned in the IAM do not result in full recovery of start-up and other costs for NQS Generators. The guarantee

programs created by the IESO, and consistently used by all U.S. ISO/RTO wholesale electricity markets, are intended to ensure that NQS Generators are fully financially compensated when they are committed and dispatched in the IAM. Section 6 provides a detailed analysis regarding the financial impacts of changes to current guarantee programs brought on by the MRP Amendments.

### 5.3 *Ontario's Installed Capacity and NQS Generation Group Capacity*

36. Ontario currently has more than 39,000 MW of total installed transmission-connected generation capacity supply. Currently, more than half of that installed capacity comes from nuclear (13,200 MW) and hydroelectric (8,800 MW) generation that were, in most cases, built decades ago prior to Market Opening. Looking ahead, nuclear generation is expected to decline over the next decade, as the Pickering Nuclear Generating Station ("PNGS") fully retires in 2026 – removing around 3,100 MW of baseload capacity – and nuclear generation units at the Bruce Nuclear Generating Station ("BNGS") and Darlington Nuclear Generating Station ("DNGS") are taken offline for refurbishment.

37. The IESO lists more than 10,000 MW of transmission-connected capacity from gas-fired or oil-fired generation capacity – with the 2,100 MW Lennox Generating Station operating as a dual-fuel generation facility (and included in the IESO's gas-fired generation capacity value).[10] In total, gas-fired generation accounts for more than 25% of all installed transmission-connected generation capacity in Ontario. Many of the gas-fired generation – excluding Lennox, which is not included in the NQS Generation Group – were built after Market Opening.

38. The NQS Generation Group accounts for more than half – more than 5,000 MW – of the installed gas-fired generation capacity in Ontario. Importantly, the location of the majority of the NQS Generation Group's gas-fired generators are inside or near major load centres, with nearly all of these generators located in the Southern Ontario electricity zones to maintain power system reliability in the major cities that account for a majority of Ontario's total electricity demand.

### 5.4 *How NQS Generators Participate Within the IAM Under Legacy IAM Versus Under MRP IAM*

39. The MRP Amendments will alter the way that NQS Generators (and other supply resources) participate in the current IAM versus the post MRP IAM. As discussed in the previous section, the MRP Amendments introduce LMPs, a financially-binding DAM, new commitment programs and a wide ranging MPM framework, among other changes. The introduction of a financially-binding DAM as part of the MRP Amendments will introduce an entirely new settlement design (and risk) that will be based on what is known as a two-settlement system: one in the DAM and one in the Real-Time Market ("RTM"). RTM settlement differs from the DAM settlement to the extent an MP increases or decreases their scheduled supply from DAM, and the extent to which RTM LMPs differ from DAM LMPs. The financial and operational risk of the two-settlement system is not present in the current IAM.

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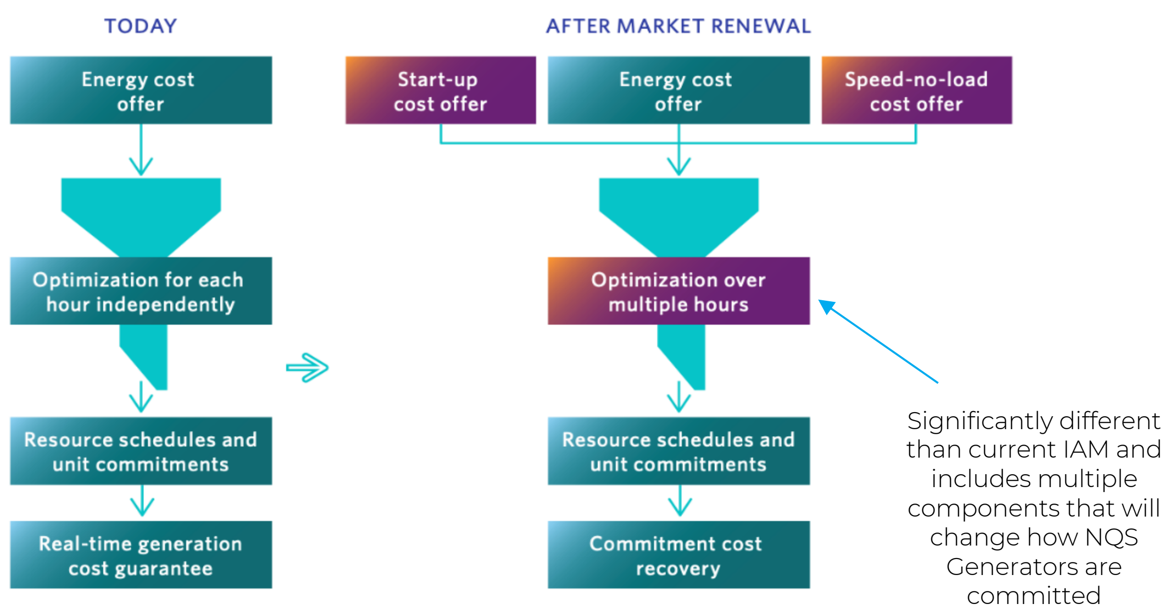
[10] The IESO does not provide details on what MWs and supply resources are included the 10,000 MW value.

40. In addition to the aforementioned settlement changes, it is important to understand how NQS Generators are committed and dispatched in the current IAM compared to the future IAM under MRP. The following paragraphs provide a high-level overview of the commitment, dispatch, and settlement of NQS Generators in the current IAM, followed by a similar overview of the future IAM under MRP. Of note in the following graphic, the "optimization over multiple hours" element of the MRP Amendments includes a number of components that are not prevalent in the current IAM, including: i) optimization of all supply resources over multiple hours, ii) optimization using three-part offers, iii) optimization of supply resources considering temporal constraints of NQS Generators (i.e., physical constraints that occur over multiple hours), iv) optimization of supply resources by simultaneously incorporating physical and economic constraints in different locations on the electricity grid, and v) incorporating the actual ramping capabilities of supply resources to be able to produce energy (whereas the current model assumes they can ramp up and down faster than their physical capabilities).

**Figure 2 Comparing Commitment and Dispatch of NQS Generators in Current Versus Future IAM**




41. *Day-Ahead Commitment Process in Current IAM*

a. The Day-Ahead Commitment Process ("DACP") process was introduced in 2006 (i.e., it was not part of the original design of the IAM at Market Opening) to improve the reliability of the electricity grid by providing better foresight into availability of supply resources for dispatch on the following day, as well as providing financial guarantee payments for NQS Generators regarding day-ahead commitments (as well as imports, which are not the focus of this report). In 2011, the IESO introduced the Enhanced DACP that included an updated commitment guarantee program for NQS Generators, among other changes.

b. NQS Generators must participate in the DACP through energy offers (both supply (MW) and price ($/MWh)), start-up costs, and SNL costs (i.e., three-part offers). The Day-Ahead Calculation Engine ("DACE") inputs all energy offers and other parameters from NQS Generators and other MPs and optimizes commitment over a 24-hour period the following day, resulting in hourly prices and schedules.

c. While the DACP and associated DACE provide dispatch schedules and associated prices for NQS Generators, the prices are not financially-binding and, apart from Day-head Production Cost Guarantee ("DA-PCG") payments, commitments are not operationally binding for supply resources operated by MPs. All non-NQS generators do not receive financially or operationally binding commitments in the DACP. Importantly, NQS Generators are committed and dispatched differently after the DACP ends, providing them with the opportunity to be committed and dispatched in the RTM based on their incremental energy offers through the Real-Time Generator Cost Guarantee ("RT-GCG") program (discussed in more detail later in this report).

42. *The Pre-Dispatch Commitment Process in the Current IAM*

a. Once the DACP is complete, the PD process begins. The PD process marks the transition from DA scheduling to RT dispatch.

b. The PD process looks ahead over future hours to provide advisory wholesale prices and schedules for NQS Generators and other supply resources. The advisory schedules allow supply resources to understand the changes in demand, supply, and other variables that will occur, as the IESO moves from the DACP (the previous day) to RT dispatch and the impact this will have on wholesale market prices and potential dispatch. NQS Generators that have received a DA-PCG commitment will have those constraints applied through the PD and RT scheduling processes. Note that any NQS Generators that have received DA-PCG commitments cannot reject it unless they go through the withdrawal process with the IESO. While historically, most commitments of NQS Generators occurred through the PD and RT processes rather than the DACP, even recent increases in DACP commitment continue to allow NQS Generators the opportunity to be committed in RT through incremental energy offers only if they have not received a DACP commitment.

c. The distinction between how NQS Generators are committed in the DACP compared to the PD process is important. The DACP includes three-part offers (not used to set wholesale prices in the DA timeframe) and optimization across a 24-hour period, whereas PD commitment is done hourly and incorporates incremental energy offers only. When an NQS Generator does not receive a DACP commitment, it can compete for commitments throughout the next day through the PD process. The DACP also has no MPM, which can allow NQS Generators to adjust offers accordingly depending on how they want to be committed or not.

d. The PD calculation engine incorporates the bids and offers that were submitted as part of the DACP. Supply resources are allowed to change their bids and offers as many times as they please up until two hours prior to respective RT dispatch hours. As noted, the PD calculation engine incorporates the DA-PCG commitments for NQS Generators throughout the PD process.

e. The PD calculation engine utilizes a one-hour Look-Ahead Period ("LAP"), which means that costs are considered over a one-hour time-period only, and constraints that last over multiple hours – such as MGBRTs for NQS Generators – are not modelled or included in the IESO's calculation engines that determine commitments and prices. The PD calculation engine is independent of the RTM calculation engine, apart from the operational commitments of NQS Generators.

f. Importantly, NQS Generators in the PD calculation engine are economically scheduled in the same manner as other supply resources – through incremental energy offers only. Provided an NQS Generator's ***incremental energy offer*** are scheduled (i.e., economic) for half of its MGBRT, NQS Generators can ***voluntarily*** invoke commitment through the RT-GCG program. By voluntarily invoking an RT-GCG commitment, an NQS Generator can ensure that it is committed and scheduled to operate for at least its MGBRT in the RTM, and that it will recover all of its start-up and SNL costs incurred to reach its MLP and maintain at that level for its MGBRT. A RT-GCG commitment must be invoked within three hours of the respective RT dispatch hour. Once the RT-GCG commitment has been invoked, the IESO will ensure the respective generation unit(s) is "constrained on" – meaning that it will run regardless of it being economic compared to the MCP – up to its MLP through its entire MGBRT. The PD calculation engine will then include the constraints for the NQS Generator and then carry them over to the RTM.

43. *The Real-Time Process in Current IAM*

a. After the PD process, RT commitment and dispatch will begin.

b. For NQS Generators, the DA-PCG and RT-GCG commitments are carried over into the RTM calculation engine. As discussed in the previous section, the RTM calculation engine includes an unconstrained market schedule (and wholesale market prices) as well as a constrained dispatch schedule (and associated shadow prices). The dispatch schedule schedules resources for the five-minute dispatch intervals and looks over 60 minutes (i.e., 12 five-minute dispatch intervals) to optimize dispatch for respective dispatch hours in RT. The market schedule looks at the previous five minutes to determine the MCP, which is then arithmetically averaged over the hour to determine the Hourly Ontario Energy Price ("HOEP"). As noted, the market schedule and associated MCP assumes there are no physical constraints on the grid (e.g., transmission losses, transmission congestion, etc.) or operational constraints (e.g., MGBRT and MLP for NQS Generators).

44. *The Settlement Process in Current IAM*

a. After RT dispatch and commitment are completed, the settlement process will begin.

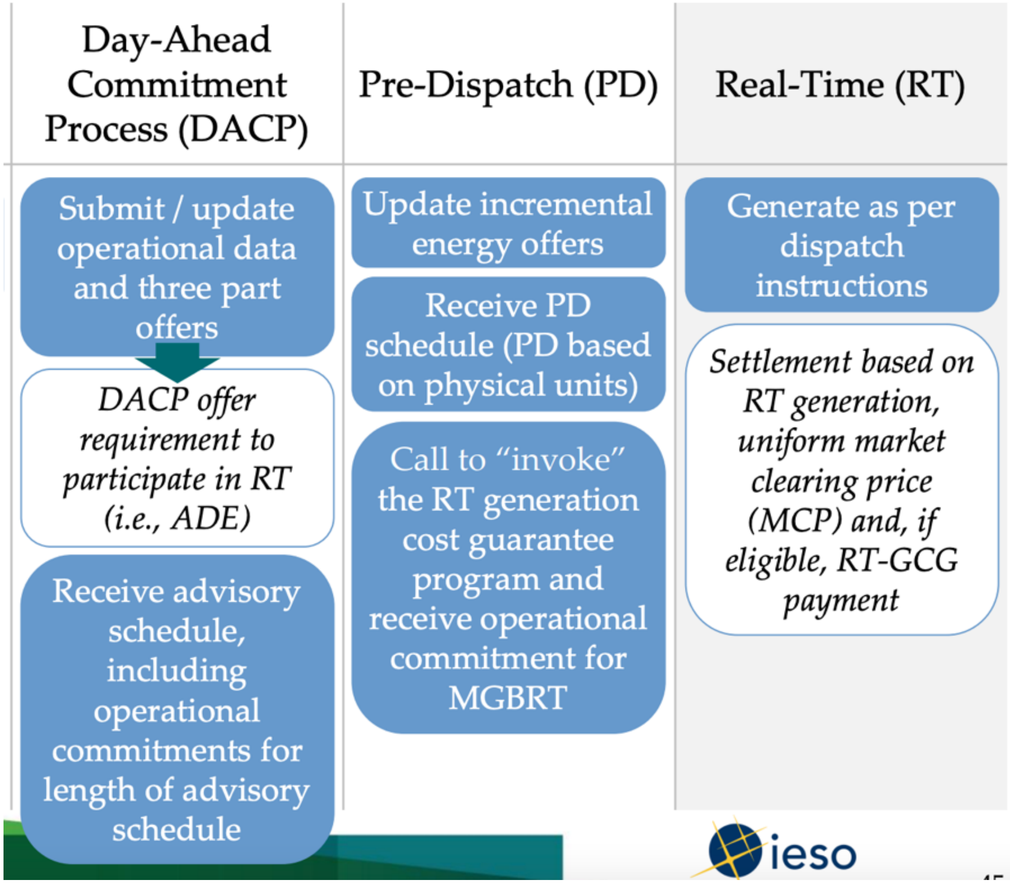
b. For NQS Generators, the RTM energy revenues in the IAM are calculated (for simplicity purposes) by multiplying the amount of supply scheduled in the unconstrained market by the MCPs.

c. CMSCs can also be paid to NQS Generators when they are dispatched out of economic merit – that is, when their dispatch schedule differs from their market schedule. The payments of CMSCs compensate for differences between implied operating profits from MPs following their dispatch schedules instead of their market schedules. This helps equalize compensation from following the dispatch schedule when it differs from the market schedule. The payments of CMSCs act as a financial bridge between the two distinct schedules and are currently a key component of the IAM.

d. The payments made through the RT-GCG program ensures that NQS Generators fully recover their incremental energy, start-up, and SNL costs if they are not earned from wholesale market revenues earned up to the MLP for its MGBRT (and excludes OR revenues). These payments occur after NQS generators have been dispatched in the RTM, with the amounts based on values submitted to the IESO by NQS Generators.

45. The following figure provided by the IESO offers an overview of the process for commitment and dispatch under the current IAM. Note the IESO's language regarding "advisory" schedules for the DACP and call for MPs to voluntarily "invoke" the RT-GCG program.

**Figure 3 IESO Overview of Commitment and Dispatch in Current IAM**




46. The following paragraphs highlight the commitment, dispatch, and settlement of NQS Generators (and other supply resources) included in the MRP Amendments. The following section will analyze the financial implications for NQS Generators due to the differences between the current Market Rules and the MRP Amendments.

47. *The DAM in MRP Amendments*

a. The current DACP process – which does not provide financially-binding schedules or wholesale prices – will be replaced with a financially-binding DAM.

b. DAM participation will be mandatory for all NQS Generators that want to participate in the RTM. The DAM will produce financially-binding schedules that are part of the new two-settlement system. The two-settlement system requires that NQS Generators that receive a schedule in the DAM need to meet that schedule in the RTM or be subject to a clawback in revenue by the IESO. For example, assume an NQS Generator has a three-hour commitment in the DAM for 100 MW and a \$50/MWh LMP in each hour. The NQS Generator's DAM commitment earns \$15,000 ((100 MW X \$50/MWh) X 3 hours). If in the RTM the NQS Generator produces 90 MW for three hours and the LMP is \$60/MWh, it will see its DAM revenues reduced by \$1,800 (((90 MW – 100 MW) X \$60/MWh X 3) = -

$1,800) for a total two-settlement of $13,200.[11] This is significantly different than the current IAM that imposes no financial risk for NQS Generators or other MPs.

c. The DAM will also include a new guarantee program, the Day-Ahead Generator Offer Guarantee ("DA-GOG"), which broadly aligns with the DA-PCG except the settlement envelope is much larger and, as such, can result in a negative impact for NQS Generators through reduced payment amounts. The negative impact is a result of the current DA-PCG not counting revenues from RT production in excess of what was committed through the DACP against the guarantee payments. As discussed further below, the future DA-GOG under the MRP Amendments will incorporate all actual revenues in the RTM against the calculated guarantee payment.

d. The PD and RT schedules are key elements of commitment and dispatch in the current IAM. Going forward, the DAM is expected to be the primary driver of commitment in the future IAM under MRP, with all supply resources receiving a financially-binding commitment (unlike the current IAM), while the PD and RTM processes are expected to largely operate as balancing services in response to changing conditions on the grid.

48. *The Pre-Dispatch Process in MRP Amendments*

a. The MRP Amendments will fundamentally change the PD commitment process for NQS Generators as part of changes included in ERUC.

b. The PD will now include a multi-hour process that will optimize energy offers and consider total costs – such as start-up and SNL costs for NQS Generators – over a maximum and contiguous 27-hour LAP. This is significantly different than the single hour optimization that occurs within today's IAM that only considers incremental energy costs when scheduling NQS Generators. This is also bespoke design compared to other U.S. ISO/RTO wholesale electricity markets, which do not include such a significant LAP and, as such, the IESO, to Power Advisory's knowledge, has not considered whether the many changes that can occur as a result of a maximum and contiguous 27-hour LAP will result in additional financial harm to NQS Generators. Optimization over a maximum 27 contiguous hours through the PD process and incorporating non-incremental energy costs for NQS Generators can significantly change the scheduling of NQS Generators in the PD timeframe from the current IAM. To Power Advisory's knowledge, the IESO has not performed analysis regarding alternate options to the ERUC design of a maximum and contiguous 27-hour LAP towards determining operational and financial implications to NQS Generators or other supply resources.

c. As noted, generation unit commitments will be made in consideration of three-part offers from NQS Generators, which include incremental energy offers, start-up costs, and SNL costs. As part of ERUC, the IESO's unit commitment calculation engine will also consider operational constraints such as MGBRT and MLPs of NQS Generators when scheduling in the PD timeframe. This approach contrasts

[11] The formula for two settlement is: (DAM Quantity * DAM LMP) + LMP RT * (Quantity RT – Quantity DAM)

the current IAM design which allows NQS Generators to voluntarily invoke the RT-GCG program when incremental energy offers are economic (or in merit) for half of the NQS Generators' MGBRT and then have the IESO manually constrain-on these NQS Generators in RT. These constraints are not included in the calculation engine to determine PD prices in the current IAM. The following section provides an example of how the consideration of operational parameters in the PD calculation engine can result in an NQS Generator not receiving a commitment, even when its offers are economic.

d. The PD calculation engine will carry over DAM commitments and schedules and potentially increase or decrease them if system conditions have changed on the grid. Given the more extensive LAP and the various constraints and inputs being applied in the PD calculation engine, schedules and commitments of NQS Generators from the DAM will be more volatile (and subjected to potentially multiple changes) than the fixed commitment in the DACP in the current IAM.

e. The cost guarantee program for the PD and RT process under MRP is the RT-GOG program and will incorporate greater IAM revenues than the current RT-GCG program in today's IAM. The difference in the RT-GOG as part of ERUC and the RT-GCG programs are discussed more extensively in the following section. Nonetheless, the more comprehensive commitment process – that includes three-part offers and a maximum and contiguous 27-hour LAP – will materially change the scheduling and dispatch of NQS Generators compared to the current IAM.

f. Similar to the DAM, the PD process will incorporate the IESO's more extensive MPM framework that will screen on an *ex-ante* basis multiple financial and operational parameters – increasing the potential of administratively lower wholesale prices (resulting in less revenues from the IAM) and operational decision making for NQS Generators. Again, this is discussed in more detail in the following section.

49. *The Real-Time Process in MRP Amendments*

a. The MRP Amendments will significantly change various pricing and commitment programs in the RTM commitment and dispatch process.

b. The current two-schedule system and associated payment of CMSCs will be eliminated and replaced with LMPs and Make Whole Payments ("MWPs") under MRP. While NQS Generators can today forecast wholesale prices based on a high-level understanding of the economic merit order across the entire IAM, the MRP Amendments will introduce the risk of various transmission and other constraints into LMPs that will be used for settlement purposes – making the forecasting of prices significantly more challenging.

c. The RTM calculation engine will also incorporate operational and other constraints for NQS Generators that are part of the DAM and PD processes. Unlike the current IAM where NQS Generators are committed based on incremental energy offers, the MRP Amendments will result in commitment on three-part offers, as discussed in other parts of this evidence.

50. *The Settlement Process in the MRP Amendments*

a. The MRP Amendments will change settlement for NQS Generators, primarily in two ways.

b. First, as noted previously, IAM revenues – including energy and OR – will be settled on LMPs rather than uniform prices (i.e., MCP and HOEP).

c. Second, the design of the RT-GOG program is significantly different and more financially restrictive than the current RT-GCG and DA-PCG programs. While the following section will provide a more detailed analysis, the combination of three-part offers, a maximum and contiguous 27-hour LAP and other constraints included in the MRP Amendments are expected to reduce commitment and dispatch of NQS Generators, while the RT-GOG and DA-PCG programs will provide less comprehensive guarantee payments when NQS Generators do not fully recover their commitment costs through IAM revenues than the current RT-GCG program.

51. *Market Power Mitigation in the MRP Amendments*

a. The future IAM under MRP will also include an extensive MPM framework that will screen and override various MP specified financial (i.e., incremental energy offers, start-up costs and SNL costs) and non-financial parameters (i.e., MGBRT, MLP and other operational inputs). MPM will be implemented on both an *ex-ante* ("before the event") and *ex-post* ("after the event") basis for economic and physical withholding, respectively. In the current IAM, MPM is applied very infrequently and is limited in scope, amounting to an after the fact clawback of CMSC payments in extreme cases of overpayment or gaming by supply resources operated by MPs.

b. Given the significant number of parameters that will be screened on an *ex-ante* basis due to the MRP Amendments, the administrative oversight and potential impact on the IAM is material compared to the current IAM.

## 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**

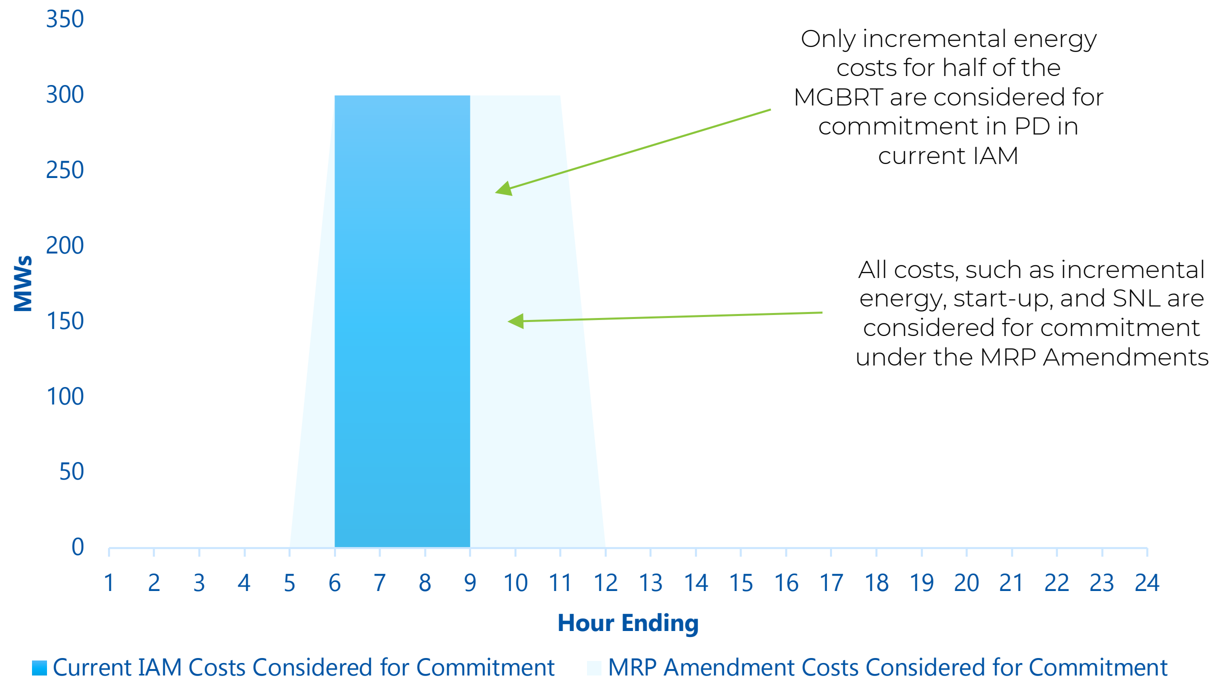



**Figure 6 Costs Included in Calculation Engine for Commitment**[14]

| | 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** |

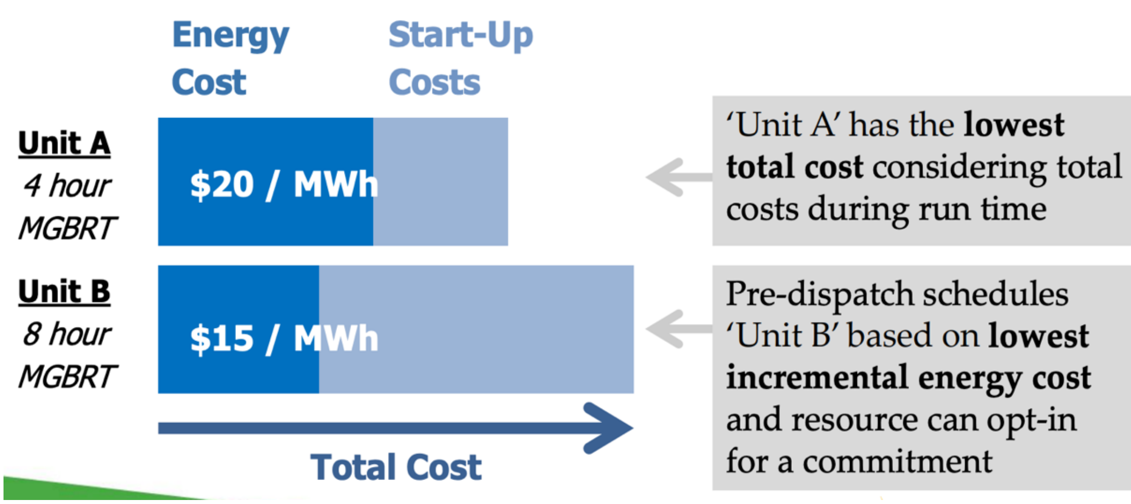
e. This highlights the different financial barriers to commitment for NQS Generators based on the current IAM compared to the MRP Amendments. In the current IAM, only the costs related to an NQS Generator's incremental energy offers for half of its MGBRT are used to invoke a commitment – if those offers 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*

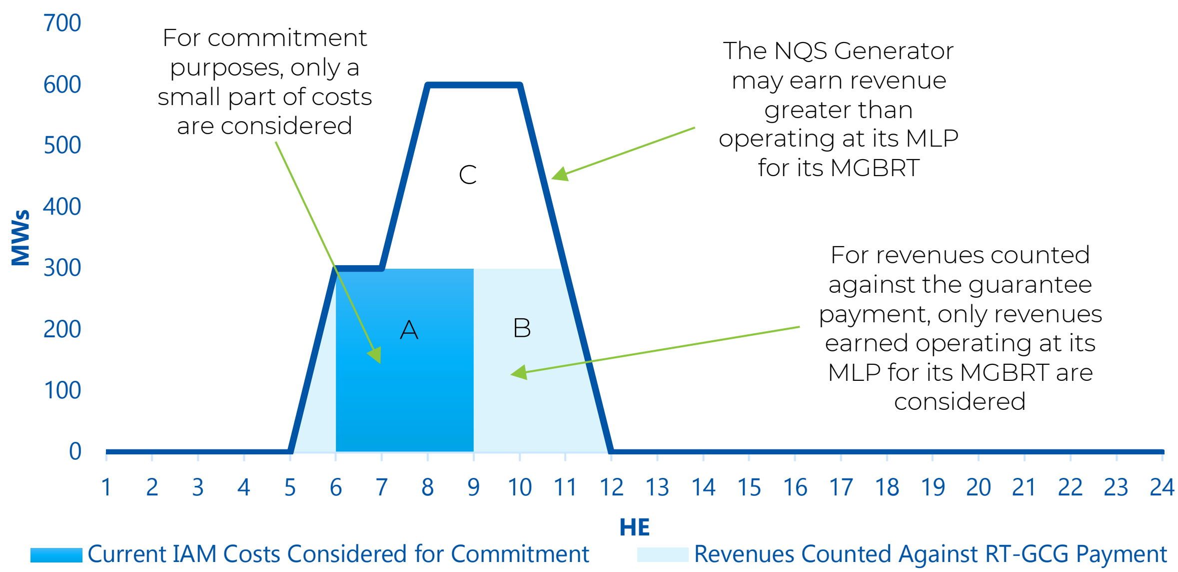
a. The MRP Amendments also include significant changes to the IESO's commitment programs for NQS Generators – particularly the elimination of the RT-GCG program and replacement with RT-GOG program that will produce negative financial outcomes for NQS Generators. At a high-level, the RT-GCG program allows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

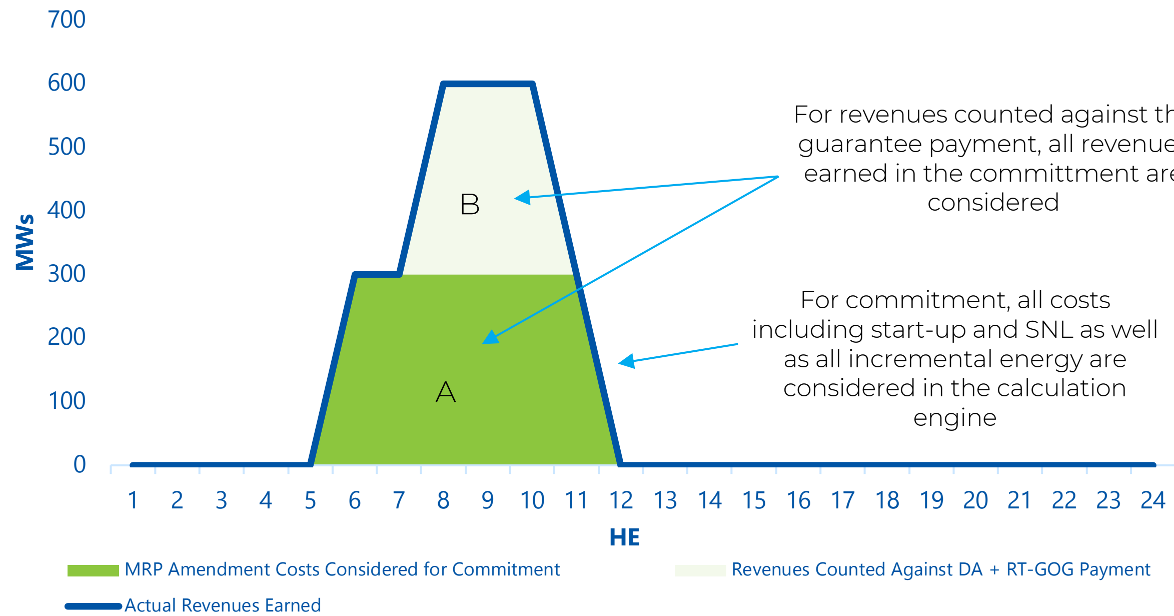



c. In the example above, only the costs in A are considered for commitment (i.e., incremental energy offers for half of its MGBRT). When calculating the RT-GCG payment – which is the difference in all of the costs to bring the generation unit online and revenues earned in the IAM – only the revenues 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.

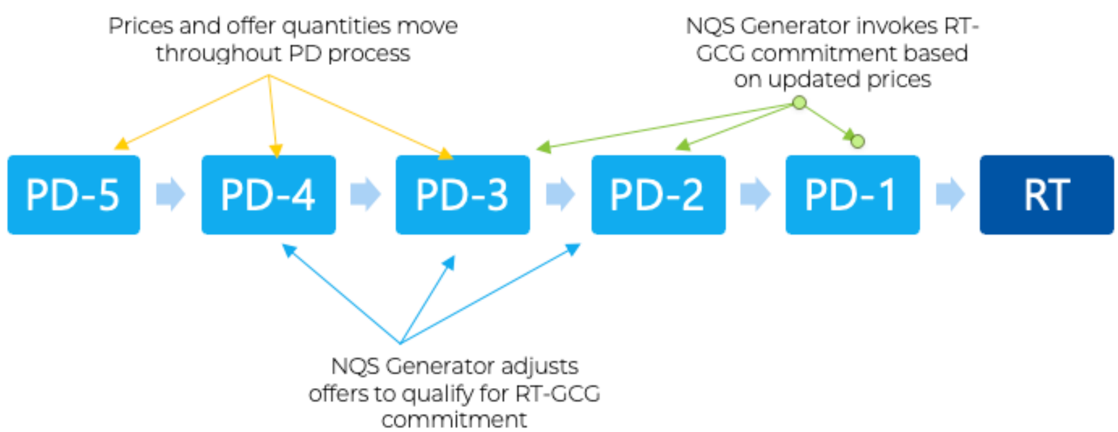
**Figure 9 Guarantee Payments Under MRP Amendments**




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.

## 7. How and Why MRP Implications for NQS Generators Matter for MRP Related Contract Amendments

69. While the NQS Generators will face financial harm from the MRP Amendments, the interaction of their current contracts with the MRP Amendments – and the additional financial risk that may impose – should also be considered in the context of Ontario's broader electricity market.

### 7.1 *Ontario's Electricity Market Structured on Combination of IAM and Contracts*

70. Ontario has what is known as a "hybrid" market structure – meaning it is a combination of a competitive wholesale electricity market that sets prices in the DAM and the RTM, as well as extensive contracting and rate-regulation structure that provides essential out-of-market payments to nearly all supply resources. Nearly all supply resources in the IAM are, or were at one time, provided compensation outside of the IAM to ensure their operations and investments are financially viable. Apart from rate-regulated generation, nearly every contracted supply resource is contracted with the IESO. Ontario's unique hybrid market is different than other competitive wholesale markets where supply resources either rely wholly on the wholesale market for revenues, capacity markets or bilateral contracts with a buyer that is not an ISO or RTO.[20]

71. While MRP initially adopted an approach to move supply resources in the IAM away from contracts to a forward capacity market (i.e., IESO originally included the Incremental Capacity Auction ("ICA") within MRP), that approach was ultimately abandoned in 2019 by the IESO in recognition that procurement contracts are an essential part of Ontario's electricity market. The IESO is now running multiple procurement processes for new projects that are offering (20+ years) contract term lengths, as well as procurements for existing supply resources to maintain their operation post expiry of their contracts, that include medium (3-5 years) commitments. The current suite of procurement processes being administered, or planned to be administered, by the IESO will maintain the existing hybrid market structure. The likelihood of a significant number of supply resources participating in the IAM on a merchant – i.e., uncontracted – basis is unlikely given the lack of sufficient revenue to be made in the IAM, as well as the significant regulatory risk associated with unforeseeable future changes to the IAM that cannot be hedged, as was the case with the MRP Amendments for generators that invested prior to their development. In recognition of this, the procurements are being designed with due consideration for the market risks introduced with the MRP Amendments.

### 7.2 *Generation Resource Investments Based on Combination of IAM and Contract Revenues*

72. Given Ontario's electricity hybrid market structure, supply resources, including NQS Generators, make investment decisions based on the design and rules of the IAM and

[20] Note that contracting agencies such as NYSERDA are increasingly entering into long-term contracts that more broadly align with the Ontario approach.

its interaction with contract terms and conditions at the time of investment. In essence, the decision to invest within the IAM requires NQS Generators and all other supply resources to assess both IAM market design/rules and contract terms and conditions simultaneously. Neither of those two components can be fully divorced from the other, given Ontario's hybrid structure. Any financial impact due to amendment of the Market Rules will flow through to contracts and vice versa – neither the contracts nor the IAM operates in isolation from the other.

73. Most NQS Generators contracted with the former OPA, now IESO[21], circa 2006 to 2010. The operating parameters for the supply resources were established based on an understanding and view of Ontario's electricity market that existed at that time, including the current IAM components discussed in the previous sections of this report. The MRP Amendments fundamentally alter these components and the broader design of the IAM and, in the process, puts the invested capital of these supply resources at risk.

74. The Ontario wholesale energy market has historically failed to provide sufficient revenues to finance, build, construct and operate new generation. The contracts are designed to work with the wholesale energy market as a hedge against net market revenue – i.e., provide generators with an additional revenue stream to bring new generation online. The Final Report of the Electricity Conservation and Supply Task Force, dated January 2004, stated that: *"The Task Force recommends less reliance on the spot market as a signal for new investment. There should, instead, be greater reliance on long-term contracting between generators and large volume buyers."*[22]

75. The contracts pay the NQS Generators based on the difference between the NQS Generator's net revenue requirement ("NRR"), which is the amount of money it needs net of variable operating costs to cover the cost of building and financing the new generation, as well as the fixed costs associated with operating the generation and deemed or imputed net market revenue ("INR"). The calculation of INR is based on the deemed operation of gas-fired generation in the IAM based on the NQS Generators' incremental energy cost and certain market signals such as HOEP, pre-dispatch prices and the price of natural gas. Payments to the NQS Generators depend on the difference between NRR and INR. If INR is less than NRR, then there is a net payment to the NQS Generator, called a contingent support payment, but if INR is greater than NRR, the NQS Generator pays the difference to the IESO as a revenue sharing payment.

76. For example, if an NQS Generator's NRR is $10 million and it is deemed to earn $7 million in INR, it would be paid $3 million as a contingent support payment under the contract. If it were deemed to have earned $12 million in INR, it would pay $2 million to the IESO as a revenue sharing payment.

77. If an NQS Generator earns actual net market revenue ("ANR") that is less than its INR, it suffers financially. The contract deems that INR is earned in the market and adjusts

[21] OPA was merged into IESO in 2014 [NTD: check date]
[22] https://suzyhomemaker35.tripod.com/sitebuildercontent/sitebuilderfiles/ecstf.pdf

the payment to the generator based on this, so if a generator does not earn at least as much ANR as INR, it suffers a payment shortfall and suffers financially.

78. Using the example set out above, if the contract deemed the NQS Generator to earn $7 million in INR, yet it only earned $5 million in ANR, its payment under the contract would still be $3 million, however its total net revenue would only be $8 million ($3 million paid under the contract and $5 million in net revenue from the market). The NQS Generator needs $10 million in net revenue to operate its units, so it suffers a net revenue shortfall of $2 million.

79. The contracts currently operate as a reasonable, but not perfect, hedge against net market revenue. To the extent that the contracts are not a perfect hedge against net market revenue, the NQS Generators can rely on the RT-GCG program to provide for supplemental revenue. An NQS Generator can self-commit its units if an NQS Generator receives a pre-dispatch schedule for half of its MGBRT. This enables the NQS Generator to be online and earning ANR when it is being deemed to earn INR, as discussed in the detailed example included in the Appendix.

80. The IESO's propose contract amendment term sheet does not address the additional complexity and risk to which the NQS Generators are exposed under MRP:

a. Commitments under MRP will be determined by the economics of three-part offers, whereas the term sheet continues to determine assumed operations based on incremental energy offers only. As a result, the NQS Generators' units will be rendered less competitive and be committed less often under MRP than they are today (all else being equal), but there is no commensurate reduction in assumed competitiveness or commitment under the term sheet. This will result in ANR being less than INR, and the deterioration of the quality of the hedge.

b. Commitments under MRP will be determined based on the NQS Generators economics over a 24-hour period, whereas the term sheet continues to determine assumed operations based on an hour-by-hour assessment. Consequently, the NQS Generators' units will be committed less often under MRP than they are today (all else being equal). This will result in a reduction in ANR relative to INR, and the deterioration of the quality of the hedge.

c. Commitments under MRP will incorporate the impact of physical constraints elsewhere on the grid, whereas the term sheet does not consider such constraints. The incorporation of these physical constraints under MRP will result in the NQS Generators' units being committed less often despite appearing economic. This will result in ANR being less than INR and the deterioration of the quality of the hedge. Furthermore, the black box nature of commitment decisions under MRP will not allow the NQS Generators to assess why their units failed to receive a commitment despite appearing economic, even after the fact. The MRP Amendments expect the NQS

Generators to accept the risk of this occurring before any experience is gained operating in the renewed MRP IAM.

d. The RT-GCG program can provide a mitigation tool to align dispatch in the IAM with the contracts. Under MRP, no such mitigation tool exists, exposing NQS Generators to the full impact of the above-noted risks and highlighted in the example included in the Appendix.

81. The NQS Generators will not be able to earn the IAM revenues they had contemplated earning when they made their investment decisions, as a result of the MRP Amendments. The risk associated with lower IAM revenues resulting from MRP related amendments to the Market Rules is not a risk that they can control, and with only one electricity buyer in Ontario (i.e., IESO), it is not a risk that they can hedge. Consequently, the NQS Generators would suffer financial harm that would not occur but for the MRP Amendments.

82. Therefore, considering that needed supply resources base investments on the combination of IAM revenues and contracts, the IESO must consider how changes to IAM design and amendments to the Market Rules impact contracts, and how amendments to contracts impact how supply resources participate within IAM. The IESO actively worked with other supply resources – notably wind and solar generators – to ensure that MRP related changes to the design of the IAM would not impose financial harm.[23] Additionally, OPG's EB-2023-0336 application – reviewed by the OEB – addressed the impact of MRP on certain areas of OPG's rate-regulated framework. ‹In both cases, the MRP Amendments either resulted in effective amendments to the contracts to prevent financial harm (wind and solar generators) or initiated a review (OPG rate-regulated generators).

83. The IESO does not have a formal contractual mechanism/forum (e.g., on-going stakeholder engagement initiative) to review and address the interaction of contracts with changes to the design of IAM and amendments to the Market Rules.[24] The IESO did provide the NQS Generators with proposed contract amendment term sheets and have held meetings and webinars with the NQS Generators, but has not provided any supporting analysis for the proposed amendments. Therefore, a review of the MRP Amendments is necessary to fully consider their financial impact on supply resources operating within the IAM.

### 7.3 *IESO Posed MRP-Related Contract Amendments to NQS Generators*

84. The IESO's proposed contract amendments to NQS Generators do <u>not</u> fully consider MRP design and its MRP Amendments and the financial implications to NQS

[23] See the IESO's approach to amending other contracts as a result of the MRP Amendments: https://www.ieso.ca/Market-Renewal/Background/MRP-implications-to-electricity-supply-contracts

Generators. Further, IESO's proposed contract amendments exacerbate MRP implications by their punitive nature.

### 7.4 ***Examples of Results from Past Issues Relating to Amendments to the Market Rules and Associated Contract Amendments***

85. MPs have in the past appealed amendments to the Market Rules on the basis that they impose financial harm. Notably, this occurred in the case of the IESO's SE-91 stakeholder engagement that resulted in amendments to the Market Rules (MR-00381).

86. In 2012-2013, Renewable Energy Supply Generators[25] ("RES Generators") appealed MR-00381 amendments to the Market Rules to the OEB under s. 33(1) of the *Electricity Act, 1998*, on the basis of unjustly discriminatory amendments to Market Rules towards wind generators. On November 29, 2012, the IESO Board of Directors passed five related amendments to the Market Rules (the "Variable Generator Amendments"), which fundamentally changed how the RES Generators would operate in the IAM[26]. Prior to the implementation of the Variable Generator Amendments, the RES Generators were classified as Intermittent Generators within the IAM, where Intermittent Generators were on balance not subject to following IESO dispatch instructions and therefore on balance not subjected to curtailment of energy production. The Variable Generator Amendments defined a new class of generator called Variable Generators and made the RES Generators members of this new generator class. With Variable Generators, the IESO incorporated these supply resources within the existing dispatch process, which enabled the IESO to issue dispatch instructions to curtail the energy production from the RES Generators (and all other wind and solar generators registered to participate within IAM). The RES Generators made their investment decisions relying on the then-existing Market Rules that classified them as Intermittent Generators without the risk of their energy production being curtailed by the IESO. The Variable Generator Amendments resulted in financial harm by materially affecting the economics of the wind generators owned by the RES Generators through lower IAM revenues due to curtailed production than had been contemplated when the RES Generators made their investment decisions upon executing RES I and RES II contracts with OPA.

87. Ultimately, the RES I and RES II contracts were effectively amended by the OPA to provide financial compensation to the RES Generators whenever the IESO curtailed

[25] Acciona Wind Energy Canada Inc., Brookfield Power Wind Prince LP, CP Renewable Energy (Kingsbridge) Limited Partnership, Erie Shores Wind Farm Limited Partnership, Greenwich Windfarm, LP, Talbot Windfarm, LP, Enbridge Renewable Energy Infrastructure Limited Partnership, Kruger Energy Port Alma LP, Suncor Energy Products Inc., Canadian Renewable Energy Corp., and Canadian Hydro Developers, Inc.

[26] MR-00381-R02: Dispatching Variable Generation
MR-00381-R03: (Floor Prices for Variable and Nuclear Generation)
MR-00381-R04: (Market Schedule and Congestion Management Settlement Credits (CMSC) for Variable Generation)
MR-00381-R05: (Tie Breaking for Variable Generation)
MR-00381-R06: (Publication Requirements: 5-Minute Forecast for Variable Generation).

their energy production While the Variable Generator Amendments to the Market Rules proceeded, and the harm to wind generators enshrined, that harm was effectively undone via contract amendments. Consequently, the RES Generators withdrew their appeal to the OEB.

88. The appeal of the Variable Generator Amendments – and their subsequent withdrawal of the appeal of the amendments to the Market Rules – demonstrates the linkage between revenues earned in the IAM and contracts. Similarly to the NQS Generators, the RES Generators appealed market design changes and associated amendments to the Market Rules due to the impact of financial harm on their wind generators.

89. The IESO has reiterated that MRP was not an exercise of punishing certain MPs at the expense of others. In fact, IESO Contract Management has stated multiple times that the MRP Amendments will "not extract value from contracts":

a. *"Market Renewal will create a more efficient dispatch of resources, lowering the fuel and variable costs to gas generators, while keeping them whole to the net profits (capacity plus energy margins, minus fuel costs) contemplated in their contracts. Thus, gas generators' profitability can be maintained even while passing fuel cost savings on to customers."*[27]

b. *"It is not an objective of the IESO to extract financial value from contracts by way of the MRP... The IESO's focus will be on making principled amendments based on the provisions of the applicable contract and not on achieving a particular commercial outcome."*[28]

c. *"Market Renewal is focused on improving the efficiency of Ontario's electricity markets, consistent with contract provisions and fairness to all contract counterparties, the IESO is not targeting to extract value from contracts."*[29]

d. *"Not seeking to extract value from contracted resources."*[30]

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[27] https://www.ieso.ca/-/media/Files/IESO/Document-Library/market-renewal/Benefits-Case-Assessment-Market-Renewal-Project-Clean-0170420.pdf&sa=U&ved=2ahUKEwjKkfiJxtqJAxWjEVkFHaIZOF0QFnoECAkQAg&usg=AOvVaw0IF2jUz0Jl6CtApfbVUD7R

[28] https://www.ieso.ca/-/media/Files/IESO/Document-Library/market-renewal/IESO-Approach-to-implement-MRP.pdf

[29] https://www.ieso.ca/-/media/Files/IESO/Document-Library/public-info-session/2018/EA-variable-generators.pdf&sa=U&ved=2ahUKEwjYreGIzdqJAxUbEFkFHZdZEBgQFnoECAsQAg&usg=AOvVaw0PPXFLomSbCGyHgxS8abS-

[30] https://www.ieso.ca/-/media/Files/IESO/Document-Library/public-info-session/2018/EA-hydro-electric-generators.pdf&sa=U

e. *"The MRP is focused on improving the efficiency of Ontario's electricity markets and is not targeting to extract value from contracts."*[31]

90. However, the contract amendments proposed by the IESO to the NQS Generators do not compensate them for financial losses they will incur in the IAM resulting from MRP related amendments to the Market Rules, so they effectively do extract value from the NQS Generators. In summary, the proposed contract amendments do not address the implications resulting from the MRP design and amendments to the Market Rules, as outlined above.

91. Therefore, this present situation jeopardizes the investments made by gas-fired generators owned/operated by the NQS Generators – especially at a time where Ontario requires significant supply to meet its needs.

[31]https://www.ieso.ca/-/media/Files/IESO/Document-Library/market-renewal/MR-Electricity-Supply-Contracts-20171031.pdf&sa=U&ved=2ahUKEwjjycC709qJAxUJD1kFHaYRFHgQFnoECAMQAQ&usg=AOvVaw0OYrrIUJiPGUGodZPYDky-

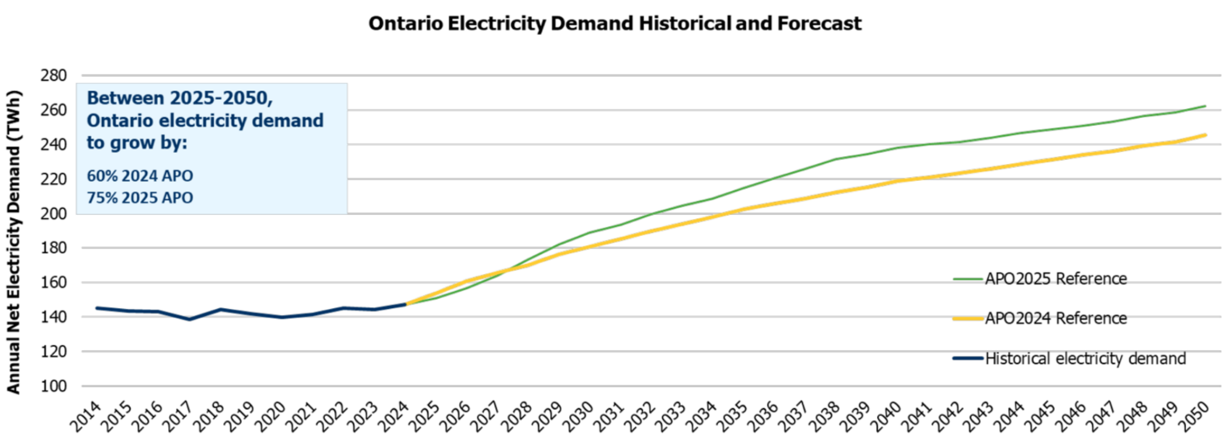
## 8. Other Important Considerations

92. After more than a decade of significant supply surpluses and low wholesale energy prices, Ontario is facing the need for new significant amounts of supply. Given the supply needs and changing resource mix, NQS Generators will play a vital role in maintaining both reliability and the ongoing integration of non-emitting, variable sources of supply.

### 8.1 *Ontario's Significant Supply Needs*

93. The demand forecast underpinning the IESO's 2025 Annual Planning Outlook ("APO") projects total energy demand to grow by 75% by 2050 – up from the 60% growth forecast the IESO included in the 2024 APO. The demand growth is expected to come from multiple sectors, including industrial facilities and data centres, growth from the commercial sector and decarbonization investments such as Electric Vehicles ("EVs") and space heating conversions from natural gas to electricity for residential customers. In total, electricity demand is expected to hit 260 TWh by 2050 – up from around 137 TWh today.

**Figure 14 2025 APO Energy Demand Growth**




94. The APO also expects Ontario to move to a "dual peaking" jurisdiction – meaning peak energy demand will occur similarly in both the winter and summer months. A dual-peaking grid will require supply resources that can provide capacity throughout the year. Peak demand is expected to grow to more than 35,000 MW by 2050 – up from the current peak demand of just under 24,000 MW.

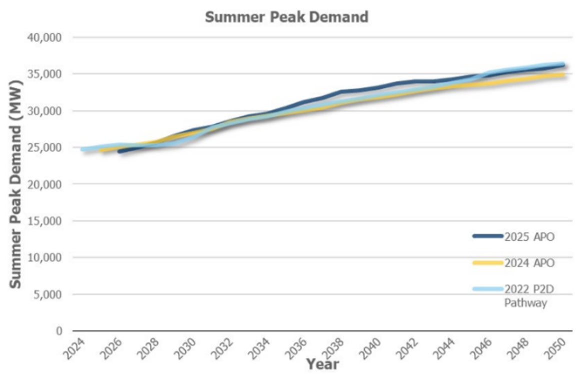
**Figure 15 2025 APO Peak Demand Forecast**

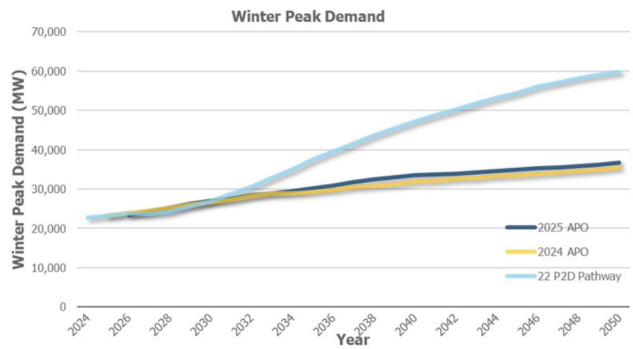
## Seasonal Peak Demand

The system is forecast to become dual-peaking by 2030, with summer and winter peaks both around 27 GW

**Average Annual Growth Rate Over Forecast Period**

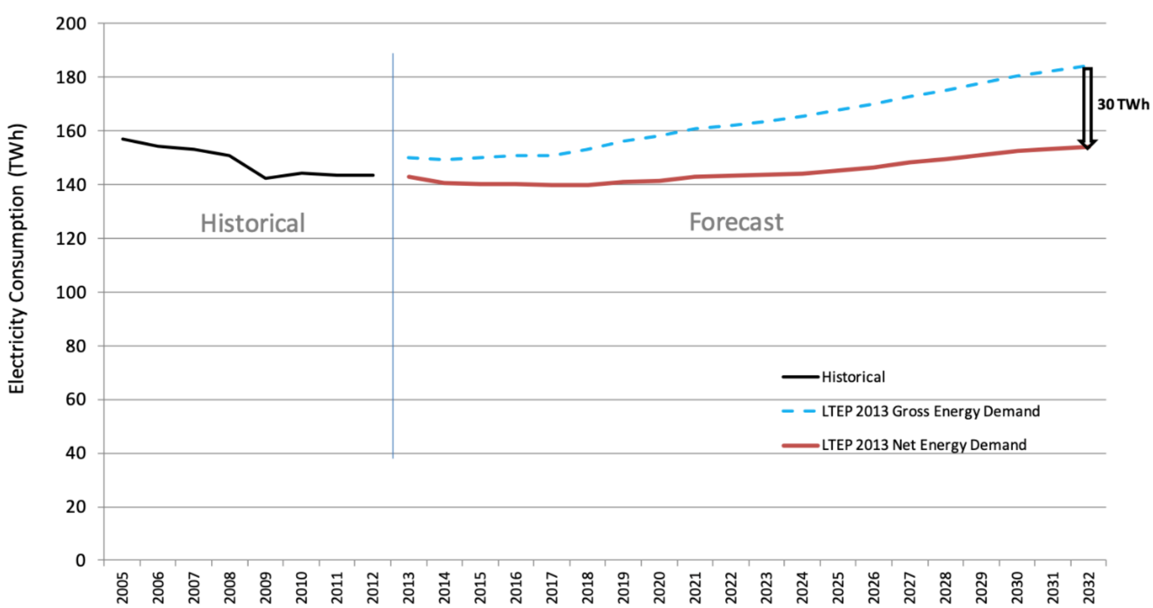
| | 2025 APO | 2024 APO | 2022 Pathways to Decarbonization (P2D) Study |
|---|---|---|---|
| Summer Peak | 1.7% | 1.5% | 1.5% |
| Winter Peak | 2.0% | 1.8% | 3.8% |



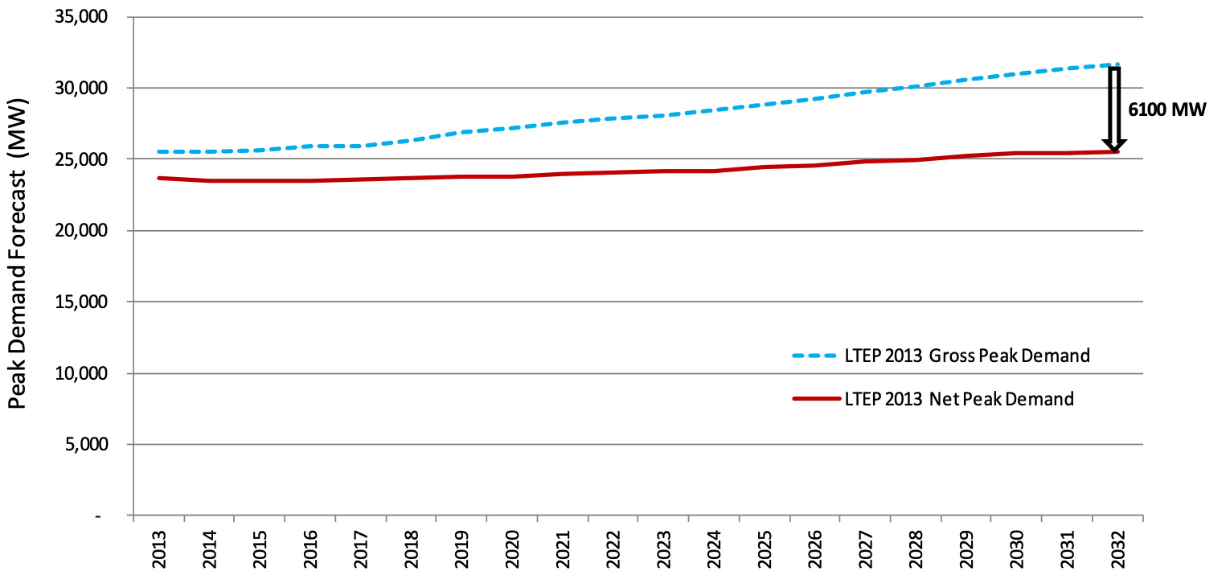

95. The supply needs being forecasted by the IESO are largely unprecedented and mark the largest increase in demand since Market Opening in 2002. For reference, the 2013 Long-Term Energy Plan ("LTEP") from the provincial government was forecasting significantly smaller growth in both energy and peak demand relative to those same years as forecasted in the 2025 APO. The energy forecast in the 2013 LTEP was expected to reach around 155 TWh by 2032, compared to nearly 200 TWh in the 2025 APO.

**Figure 16 2013 LTEP Energy Demand Growth**



96. The peak demand forecast in the 2013 LTEP was expected to hit around 25,000 MW in 2032, compared to around 27,000 MW in the 2025 APO.

**Figure 17 2013 LTEP Peak Demand Forecast**




### 8.2 *Why NQS Generators Needed to Meet Ontario's Significant Supply Needs*

97. NQS Generators are particularly important in both meeting the forecasted capacity supply needs, as well as to provide operational benefits through being capable of providing supply in nearly every hour of the year and ramping supply up and down in response to variable supply and demand fluctuations on the grid. Both the IESO and the Ontario government have repeatedly highlighted the importance of NQS Generators.

a. *"As a highly flexible resource, gas delivers energy when it is needed most, providing almost three quarters of the system's ability to respond quickly to changes in demand. Newer forms of supply, such as energy storage, are not ready to operate at the scale that would be needed to compensate…"*[32]

b. *"Even if these practical considerations could be overcome, the most optimistic assumptions show that without gas generation, Ontario's electricity system would see frequent and sustained blackouts in 2030."*[33]

[32] Gas Fired Phaseout Study
[33] Gas Fired Phaseout Study

c. *"Natural gas generation currently plays a key role in supporting grid reliability, with the ability to respond to changing system needs in ways other forms of supply cannot."*[34]

d. *"There is currently no like-for-like replacement for natural gas and the IESO has concluded it is needed to maintain system reliability until nuclear refurbishments are complete and new non-emitting technologies such as storage mature."*

98. The IESO has also specifically designed what it calls a Flexibility Mechanism that results in procuring an additional amount of OR that predominantly comes from NQS Generators. In procuring additional amounts of OR targeted at NQS Generators, the IESO will have "greater flexibility to address increased forecast uncertainty."[35] The Flexibility Mechanism – which was first discussed in 2016 and later formalized – is an explicit acknowledgment by the IESO that NQS Generators are required to maintain reliability as the grid becomes more variable. The IESO has not publicly proposed a solution to retire the Flexibility Mechanism with the adoption of the MRP Amendments.

99. The NQS Generators are also likely just as important today as when they were first contracted, considering the real challenges in building new gas-fired generators across Ontario. The province now requires municipalities to support new energy projects at a time when a number of municipalities have either publicly opposed expansions at existing NQS Generators or adopted decarbonization targets. Highlighting the challenges of procuring new gas-fired generation, the IESO was unable to contractually procure their targeted number of gas-fired generation MWs in its most recent procurements, including the Expedited-LT1 and LT1.

### 8.3 *Ontario Government Position on Need for NQS Generators to Meet Ontario's Significant Supply Needs*

100. Since the current Ontario government was formed in 2018, the IESO has received the following Ministerial Directives relating to contractually procuring operating gas-fired generators with expiring contracts, and/or new gas-fired generation projects:

a. August 23, 2023 – IESO Directed to Move Forward on Long-term Procurement and Small Hydro Program

b. April 27, 2023 – Minister Issues Directive on Brighton Beach

[34] Powering Ontario's Growth
[35] Market Surveillance Panel: https://www.oeb.ca/sites/default/files/msp-monitoring-report-20200716.pdf

c. October 7, 2022 – Minister Issues Directive on Procurement of Electricity Resources and Resource Eligibility

d. January 28, 2022 – Minister Issues Directive on Procurement of Electricity Resources

101. More recently, as part of the Ontario Government's "Ontario's Affordable Energy Future: The Pressing Case for More Power", gas-fired generation is described as "the province's insurance policy, providing this reliability on the hottest and coldest days of the year when other resources like wind and solar are not available". Minister Lecce is further quoted stating, "Our competitive ***all-of-the-above*** approach will deliver more affordable power to our families – with non-emitting nuclear energy as our anchor – to keep costs and emissions down without a costly and unnecessary carbon tax."[36] (emphasis added)

102. Interestingly, the volume of Ministerial Directives to the IESO relating to MRP is overly outweighed by Ministerial Directives to IESO relating to Ontario's supply needs and procurement of supply to meet these needs.

[36] Ontario Ready to Meet the Challenge of Soaring Energy Demand, Government of Ontario New Release, October 22, 2024: https://news.ontario.ca/en/release/1005215/ontario-ready-to-meet-the-challenge-of-soaring-energy-demand

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## 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.

## APPENDIX D: RELEVANT MARKET RULES AND MANUALS[38]

| MRP Document | MRP Section | MRP Section, Title or Topic |
|---|---|---|
| Market Manual 4: Market Operations, Part 4.2: Operation of the Day-Ahead Market (MM 0.4.2) | Appendix A (A.1-A.3) | Day Ahead Market Calculation Engine – Pass 1, 2, and 3 |
| | 2.2 | Day Ahead Market Process Timeline |
| | 2.3 | Day Ahead Market Calculation Engine Initializing Conditions |
| | 3.2 | IESO Data Inputs – Constraint Violation Penalty Curves, Market Power Mitigation Information, IESO Reliability Requirements, Resource Reliability Constraints, Demand Forecasts, Centralized Variable Generation Forecast, IESO-Controlled Grid Information, Operating Reserve Requirements |
| | 5.1 | IESO Day Ahead Reliability Commitments for GOG-Eligible Resources – Principles for Applying Reliability Commitments |
| | 5.2 | IESO Day Ahead Reliability Commitments for GOG-Eligible Resources – Process for Applying Reliability Commitments |
| | 6.3 | Results from the Day Ahead Market – Day Ahead Operational Commitments |
| | 6.5 | Day Ahead Market Economic Operating Points |
| | 8.1 | Withdrawal from Commitment (operational commitment) |
| | 8.2 | IESO Cancellation of Day Ahead Operational Commitments for GOG-Eligible Resources |
| | 8.3 | Day Ahead Operational Commitment Cancellation Cost Recovery |
| Chapter 0.7 | 2.1.14 | Requirements for Operating on the Grid – provision of relevant materials so IESO can determine reference levels |
| | 3.1.11 | Establishing an Availability Declaration Envelope |
| | 3.3.3 | Submissions During the Real-Time Market Unrestricted Window for Hourly Dispatch Data Parameters |
| | 3.3.5 | Revisions During the real-Time Market Mandatory Window for Hourly Dispatch Data Parameters |
| | 3.3.7 (specifically 3.3.7.3) | Revisions During the Real-Time Market Restricted Window for Daily Dispatch Data Parameters |
| | 3.3.17 | IESO Authorities to Direct Submission or Revision of Dispatch Data (invokes market power mitigation and reference levels) |
| | 3.4.1.1 | The Form of Dispatch Data – dispatchable generation resource (invokes three-part offers, etc.) |

[38] The list above has been constructed on a reasonable efforts basis and to the extent a rule or appendix is excluded, but is also relevant to this evidence, we would invite the IESO to notify the OEB of this basis.

| | | |
|---|---|---|
| | 3.5.4 | Hourly Dispatch Data Parameters (invokes three-part offers) |
| | 3.5.7 | Hourly Dispatch Data Parameters (ramp rates) |
| | 3.5.8 | Hourly Dispatch Data Parameters (ramp rates – OR, reference levels) |
| | 3.5.12 | Hourly Dispatch Data Parameters (start-up offers by thermal state for NQS) |
| | 3.5.13 | Hourly Dispatch Data Parameters (speed-no-load offer for NQS) |
| | 3.5.22 | Daily Dispatch Data Parameters |
| | 3.5.29 | Daily Dispatch Data Parameters (MLP) |
| | 3.5.30 | Daily Dispatch Data Parameters (MGBRT) |
| | 3.5.31 | Daily Dispatch Data Parameters (MGBRT per thermal state) |
| | 3.5.32 | Daily Dispatch Data Parameters (lead time per thermal state) |
| | 3.5.33 | Daily Dispatch Data Parameters (ramp up to MLP per thermal state) |
| | 3.5.35 | Daily Dispatch Data Parameters (thermal state) |
| | 3A.1.6 | Information Used by the IESO to Determine Schedules and Prices (projections of forecast data and other information relating to future periods of time) |
| | 3A.2.1 | Uses of the Pre-Dispatch Calculation Engine and Real-Time Calculation Engine (to determine dispatch instructions) |
| | 4.4.1 | The Day Ahead Market – Administration of the Day-Ahead Market Calculation Engine |
| | 4.6.1 | The Day Ahead Market – Passes of the Day Ahead Market Calculation Engine |
| | 5.2.1 | Determining the Pre-Dispatch Schedule |
| | 5.2.3 | Determining the Pre-Dispatch Schedule (scheduled output will meet or exceed MLP for all hours of day ahead operational commitment) |
| | 5.3.1 | Pre-Dispatch Scheduling Process Failure |
| | 5.3.2 | Pre-Dispatch Scheduling Process Failure |
| | 5.4.1 | Administration of the Pre-Dispatch Calculation Engine |
| | 5.5.1 | Information Used by the Pre-Dispatch Calculation Engine |
| | 5.6.1 | Passes of the Pre-Dispatch Calculation Engine |
| | 5.8.3 | Issuing Market Participant-Specific Pre-Dispatch Information - Other Information (approval / rejection of availability declaration envelope) |
| | 6.3.1 | Administration of the Real-Time Calculation Engine |
| | 6.4.1 | Information Used by the Real-Time Calculation Engine |
| | 6.5.1 | Passes of the Real-Time Calculation Engine |

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|---|---|---|
| | 8.1.2 | Determining Market Prices and Economic Operating Points – Purpose and Timing of Determining Market Prices |
| | 8.2.1 | Market Prices for the Day Ahead Market and the Real-Time Market |
| | 8.3.1 | Ex-Poste Determination of Economic Operating Points (day ahead and real time market make-whole payments) |
| | 8.3.2 | Ex-Poste Determination of Economic Operating Points (lost cost economic operating points for day ahead market) |
| | 8.3.3 | Ex-Poste Determination of Economic Operating Points (lost cost economic operating points and lost opportunity cost economic operating points for real time market) |
| | 8.3.4 | Ex-Poste Determination of Economic Operating Points (economic operating points calculated using the administrative price) |
| | 10.1 | Start-up notice for DA or PD operational commitment |
| | 10.2 | Notice of Decommitment |
| | 10.3 | Day-Ahead Operational Commitment and Pre-Dispatch Operational Commitment |
| | 22.1 | Reference Levels – General (Market Power Mitigation) |
| | 22.2 | Reference Levels for Financial Dispatch Data Parameters (includes 3-part offers) (Market Power Mitigation) |
| | 22.3 | Reference Levels for Non-Financial Dispatch Data Parameters (dealing with thermal states, etc) (Market Power Mitigation) |
| | 22.4 | Resources with Multiple Sets of Reference Levels (Market Power Mitigation) |
| | 22.5 | Changes to Reference Levels (Market Power Mitigation) |
| | 22.6 | Reference Quantities (Market Power Mitigation) |
| | 22.7 | Changes to Reference Quantities (Market Power Mitigation) |
| | 22.8 | Independent Review (Market Power Mitigation) |
| | 22.9 | Market Control Entities (about ownership) (Market Power Mitigation) |
| | 22.1 | Designation of Constrained Areas (narrow and dynamic constrained areas) (Market Power Mitigation) |
| | 22.11 | Global Market Power Reference Intertie Zones (Market Power Mitigation) |
| | 22.12 | Uncompetitive Intertie Zones (Market Power Mitigation) |
| | 22.13 | Ex-Ante Validation of Non-Financial Dispatch Data Parameters (Market Power Mitigation) |
| | 22.14 | Ex-Ante Mitigation of Economic Withholding (Market Power Mitigation) |

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|---|---|---|
| | 22.15 | Ex-Post Mitigation of Physical Withholding (Market Power Mitigation) |
| | 22.16 | Intertie Reference Levels (Market Power Mitigation) |
| | 22.17 | Intertie Economic Withholding on an Uncompetitive Intertie Zone (Market Power Mitigation) |
| | 22.18 | Mitigation for Make-Whole Payment Impact in Uncompetitive Intertie Zones (Market Power Mitigation) |
| | 22.19 | Intertie Economic Withholding – Procedural Steps and Timelines (Market Power Mitigation) |
| Chapter 7, Appendix 7.5 | | The Day Ahead Market Calculation Engine Process |
| Chapter 7, Appendix 7.5A | | The Pre-Dispatch Calculation Engine Process |
| Chapter 7, Appendix 7.6 | | The Real-Time Calculation Engine Process |
| Chapter 7, Appendix 7.8 | | Economic Operating Point |
| Market Manual 4: Market Operations, Part 4.3: Operation of the Real-Time Markets (MM 0.4.3) | 2.2 | Pre-Dispatch Process |
| | 2.3.1 | Pre-Dispatch Inputs – Day Ahead Market Inputs |
| | 2.3.2.1 | Pre-Dispatch Inputs – IESO Data Inputs – Constraint Violation Penalty Curves |
| | 2.3.2.2 | Pre-Dispatch Inputs – IESO Data Inputs – Market Power Mitigation Information |
| | 2.3.2.11 | Pre-Dispatch Inputs – IESO Data Inputs – Initial Hours of Operation and Initial Hours Down |
| | 2.3.3.1 | Pre-Dispatch Inputs – Initializing Conditions – Daily Dispatch Data Across Two Dispatch Days |
| | 2.3.3.2 | Pre-Dispatch Inputs – Initializing Conditions – Advancing Day Ahead Operational Commitments |
| | 2.3.3.4 | Pre-Dispatch Inputs – Initializing Conditions – Operational Commitments Over Midnight |
| | 2.4 | Pre-Dispatch Optimization Process |
| | 2.5.1.4 | Results from the Pre-Dispatch Process – Pre-Dispatch Schedules - Scheduling Discrepancies due to Thermal States |
| | 2.5.1.5 | Results from the Pre-Dispatch Process – Pre-Dispatch Schedules - Scheduling Discrepencies due to Turnaround Time |
| | 2.5.2 | Results from the Pre-Dispatch Process – Pre-Dispatch Operational Commitments and Constraints |
| | 2.5.3 | Results from the Pre-Dispatch Process – Passing Pre-Dispatch Operational Commitments to Real-Time |
| | 3.3.2 | Real-Time Data Inputs – Real-Time Integration with the Pre-Dispatch Process |

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| | 3.3.3.1 | Real-Time Data Inputs – Real-Time IESO Data Inputs – Constraint Violation Penalty Curves |
| | 3.3.3.2 | Real-Time Data Inputs – Real-Time IESO Data Inputs – Market Power Mitigation |
| | 3.5.3 | Results from Real-Time Scheduling Process - Real-Time Market Economic Operating Point |
| | 5.6.1 | Resource Commitment Notices – Start-up Notices |
| | 5.6.2 | Resource Commitment Notices – Procedural Steps for Strat-up Notices for GOG-Eligible Resources |
| | 5.6.3 | Resource Commitment Notices - Issuing Extended Pre-Dispatch Operational Commitments |
| | 5.6.4 | Resource Commitment Notices - Notice of Decommitment |
| | 5.1 | IESO Cancellation of Commitment for Generator Offer Guarantee eligible Resources |
| | 5.11 | Pre-Dispatch Operational Commitment Cancellation Cost Recovery |
| Market Manual 4: Market Operations, Part 4.1: Submitting Dispatch Data in the Physical Markets | 2.1 | Dispatch Data to Supply and Consume Energy – Dispatchable Generation and Dispatchable Electricity Storage Resources (table comparing offer components for different types of generators) |
| | 2.1.1.3 | Dispatch Data to Supply and Consume Energy – Dispatchable Generation and Dispatchable Electricity Storage Resources – Price-Quantity Pairs - Energy Offer Price Revisions |
| | 2.1.2 | Dispatch Data to Supply and Consume Energy – Dispatchable Generation and Dispatchable Electricity Storage Resources - Start-Up Offer |
| | 2.1.3 | Dispatch Data to Supply and Consume Energy – Dispatchable Generation and Dispatchable Electricity Storage Resources - Speed No-Load Offer |
| | 2.1.4 | Dispatch Data to Supply and Consume Energy – Dispatchable Generation and Dispatchable Electricity Storage Resources - Energy Ramp Rate |
| | 2.1.13.1 | Dispatch Data to Supply and Consume Energy – Dispatchable Generation and Dispatchable Electricity Storage Resources – Minimum Loading Point after Day Ahead Market Submission |
| | 2.1.18 | Dispatch Data to Supply and Consume Energy – Dispatchable Generation and Dispatchable Electricity Storage Resources – RMP Up Energy to Minimum Loading Point |
| | 2.1.19 | Dispatch Data to Supply and Consume Energy – Dispatchable Generation and Dispatchable Electricity Storage Resources – Thermal State |
| | 2.2 | Dispatch Data to Supply and Consume Energy – Computed Pseudo-Unit Technical Parameters |
| | 2.2.2 | Dispatch Data to Supply and Consume Energy – Computed Pseudo-Unit Technical Parameters |
| | 2.4.2 | Dispatch Data to Supply and Consume Energy – Energy Ramp Rate |

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|---|---|---|
| | 3.1.1 | Dispatch Data to Supply Operating Reserve - Dispatchable Resources – Supply Operating Reserve Price-Quantity Pairs |
| | 7 | Submitting (and revising) Dispatch data (timelines for daily and hourly submissions) |
| | 7.1 | Dispatch Data Submissions by Resource Type (Table 7-2: Timing of Dispatch Data Submission) |
| | 7.2 | Dispatch Data Submissions or Revisions for the Day Ahead Market |
| | 7.3 | Dispatch Data Submissions of Revisions for the Real-Time Market |
| | 7.5 | Availability Declaration Envelope |
| | Appendix B.3 | Dispatch Data Submissions or Revisions that Expand the Availability Declaration Envelope |
| | Appendix B.4.4 | Real-Time Market Mandatory Window – Reasons Summary |
| | Appendix B.5 | Single Cycle Mode Submissions or Revisions for the Real-Time Market |
| | Appendix B.6 | Hourly Dispatch Data Withdrawal |
| | Appendix F.7 | Revision Restrictions for GOG-eligible Resources |
| Market Manual 5: Settlements, Part 5.5: IESO-Administered Markets Settlement Amounts | 2.3 | Day Ahead Market Make-Whole Payment |
| | 2.4 | Day Ahead Market Generator Offer Guarantee |
| | 2.7 | Real-Time Make-Whole Payment |
| | 2.9 | Day-Ahead Market Balancing Credit |
| | 2.11 | Real-Time Generator Offer Guarantee |
| | 2.13 | Generator Failure Charge |
| | 2.23 | Real-Time Ramp-Down Settlement Amount |
| | 2.25 | Fuel Cost Compensation Credit |
| | 2.29 | Operating Reserve Non-Accessibility Charge ands Associated Reversal Charges |
| | 4.1 | Reference Level Settlement Charges |
| | 4.3 | Ex-Post Mitigation Settlement Charges |
| | 4.4 | Settlement Mitigation of Settlement Amounts |
| | 4.5 | Independent Review Process Settlement Amounts |

## APPENDIX E: CV OF BRADY YAUCH

Brady Yauch
Senior Manager Market and Regulatory Affairs
Power Advisory LLC
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Suite 700, PO Box 32
Toronto ON M5J 2H7
Tel: 416-822-6884
byauch@poweradvisoryllc.com

## SUMMARY

An electricity market analyst and economist with more than 13 years of experience in energy market analysis and regulatory affairs. Focuses on in-depth analysis of the competitiveness and economic efficiency of wholesale energy markets and regulated utilities. Has appeared many times before the Ontario Energy Board, as an expert witness in arbitration and drafted evidence in a number of regulatory proceedings.

**Professional History**

Market Assessment Unit (MAU) IESO
*Executive Director and Economist – Consumer Policy Institute (see below)*

**Education**

York University, Masters Economics, 2012
University of Edinburgh, Masters, Cultural Politics, 2005

## PROFESSIONAL EXPERIENCE

**Market Competitiveness and Economic Efficiency**

- Oversee Power Advisory's electricity price forecasts for Ontario – providing many custom forecasts for energy facilities across the province and revenue forecasts after the expiration of PPAs for a number of market participants. Also oversees price forecasts for Alberta, NYISO, ISO-NE, PJM and numerous vertically integrated utilities, particularly across Atlantic Canada. The price forecasts include capacity, energy and ancillary services. Numerous price forecasts have underpinned contract negotiations for PPAs between multiple parties.
- Provided expert evidence before the OEB regarding the province's Export Transmission Service tariff. The work included a detailed report and model highlighting the impact of increases to the ETS rate on total system costs in Ontario.
- Provided expert evidence in a private arbitration regarding contract settlements for a large load in Ontario. The evidence included a detailed report and rebuttal report.

- Provided a detailed report to the Prince Energy Island Energy Corporation on various strategies for meeting future demand growth from non-emitting sources of supply. The analysis included a detailed dispatch and capacity expansion model, as well as a settlement model to determine total commodity costs for PEI ratepayers. The findings were presented to the Minister of Energy and other officials at the PEI Energy Corporation.
- Undertook an analysis on behalf of Electricity Canada regarding affordability of electricity and the potential cost of transitioning to a net zero electricity grid. The deliverable was a 30-page report to board of Electricity Canada. As part of the project, modelled the potential demand growth and cost of transitioning provincial electricity grids to a net zero grid. The modelling included a bill impact assessment for residential, commercial and industrial customers.
- Undertook a detailed review of a proposed BESS in New York City on behalf of the U.S. Department of Energy. The analysis included a detailed review of financial modelling and price forecasts developed by the project proponent, as well as our own price and capacity forecasts that were provided to the DOE.
- Developed a model for contract negotiations for a long-term PPA for a large hydroelectric facility. The project included, among other inputs, 20-year energy and capacity price forecasts for a publicly owned utility. The price forecasts included Ontario, NYISO, ISO-NE, New Brunswick and Nova Scotia. The engagement included multiple research projects and modelling assumptions, including demand growth, electrification investments and Levelized Cost of Energy (LCOE) calculations.
- Detailed forecasting of energy prices and demand growth across multiple Atlantic Canada jurisdictions. The forecasts were used to optimally size and site new non-emitting investment, as well as underpin potential PPA negotiations.
- Provided expert evidence in the federal tax court regarding electricity analysis and cost allocation. As part of the evidence, also provided a rebuttal. The evidence provided a detailed review of physical and financial structure of Ontario's electricity grid.
- Provided expert evidence as part of a private arbitration regarding energy retailers in Ontario and the current design of the province's wholesale electricity market. As part of the evidence, I provided testimony before the arbitrator.
- Created a dispatch model for New Brunswick and 10-year marginal price forecast.
- Modelled the impact of increasing rooftop solar penetration in Ontario on wholesale prices, capacity prices and transmission constraints.
- Led the modelling and drafting of a report on the future of gas-fired generation in Ontario for the Ontario Energy Association (OEA)
- Provided a ten-year model for integrating energy storage into Saskatchewan's energy grid.
- Modelled the impact of renewable capacity and transmission in NYISO.
- Oversaw the modelling for Ontario's move to Locational Marginal Prices (LMPs), Enhanced Unit Commitment and a Day-Ahead Market (DAM) for a consortium of gas-fired generators. As part of the engagement, the analysis was used in negotiations to contract updates to ensure the incentive structure aligns with future market design.

- Led a jurisdictional review of Pumped Generation Storage (PGS) facilities in the New York and New England wholesale markets. Reviewed market rules and dispatch efficiency of PGS facilities.
- Reviewed the financial implications of moving to LMPs in Ontario for multiple market participants. Led the drafting of memos, analysis and settlement models.
- Designed a settlement model for hydroelectric facilities in Ontario moving to LMPs
- Designed a wholesale market model for Energy Storage Canada to determine the economic benefits of increased energy storage in Ontario. Led the drafting of subsequent report.
- Worked in the Market Assessment Unit (MAU) of the Independent Electricity System Operator, which undertook analysis for the Market Surveillance Panel (MSP).
- As part of that work, provided an assessment on the economic efficiency of the offer behavior of hydroelectric plants in Ontario in response to a regulator-imposed incentive mechanism. Reviewed the efficiency of transmission rights payouts and recommended a market rule change.
- Provided a detailed review of the competitiveness and economic efficiency of Ontario's wholesale market.
- Reviewed a cost guarantee program for thermal generators and provided recommendations to improve its economic efficiency.
- Provided assistance in the MAU-led review of the Industrial Conservation Initiative in Ontario and contributed to the final report.
- Led the MAU's analysis and remarks regarding Ontario's Market Renewal Program (MRP).
- Provided public commentary on the IESO's Demand Response program and its effectiveness.
- Have provided multiple reports and opinion pieces on the economics of large-scale megaprojects across Canada.

**Regulatory Affairs**

- Led the drafting of numerous chapters of a rate application by a LDC (Grimsby Power) before the OEB.
- Led a study for the Government of Northwest Territories on interruptible rates and incremental revenues for utilities. As part of the project, modelled NWT's electricity grid and the impact of incremental load through electrification investments.
- Led the drafting of a report for the Ontario Energy Association on how programs could be designed to increase energy demand in Ontario.
- Designed a cost allocation model for an LNG plant in Northern Ontario.
- Participated in hearing regarding Enbridge Gas Distribution's proposed Renewable Natural Gas (RNG) Enabling Program and Geothermal Energy Service (GES) Program (EB-2017-0319). Led the drafting of interrogatories, cross examination and final argument.

- Participated in regulatory hearing to approve the merger of Enbridge Gas and Union Gas. Submitted evidence (jurisdictional review) in the proceeding (EB-2017-0306/07), as well as led the drafting of interrogatories, cross examination and final argument.
- Participated in a hearing in response to a motion from OPG to review its rate application decision (EB-2018-0085). Drafted the organization's submissions.
- Led an intervention in the proceeding for Hydro One's 2018 – 2022 distribution rates (EB-2017-0049).
- Drafted interrogatories and final argument for an intervenor in the OEB application by Union
- Gas for approval of its 2015 natural gas Demand Side Management (DSM) conservation programs (EB-2017-0323/0324).
- Participated as an intervenor and party to the settlement of Westario's application to the OEB to set its distribution rates in 2018 (EB-2017-0084)
- Participated in hearing for Hydro One Remote Communities 2018 revenue requirement and customer rates for the distribution and generation of electricity (EB-2017-0051). Led the settlement agreement and drafted all interrogatories for client.
- Drafted comments to the Ontario Energy Board modernization panel.
- Participated as an intervenor and party to the settlement of Union Gas' application for distribution, transmission and storage of natural gas rates (EB-2017-0087).
- Participated in a hearing to set Ontario Power Generation's 2017-2021 rates (EB-2016-0152).
- Drafted the final argument, interrogatories and led cross examination.
- Participated as in intervenor in the OEB hearing to set Hydro One's 2017-2018 transmission rates (EB-2016-0160). Drafted the final argument, interrogatories and led cross examination.
- Participated in hearing and settlement conference for the Independent Electricity System Operator's (IESO) 2017 fees application (EB-2017-0150)
- Participated in settlement conference for Enbridge's application to the OEB for the disposition of deferral and variance account balances (EB-2017-0102).
- Led intervention in the application from Five Nations Energy Inc. (FNEI) to the OEB to set its transmission rates for 2017-2020 (EB-2016-0231). Drafted the final argument, interrogatories and led cross examination.
- Participated in the community gas expansion hearing before the OEB (EB-2016-0004). Drafted the final argument, interrogatories and led cross examination.
- Participated in the hearing before the OEB regarding plans from Union and Enbridge to comply with the province's cap and trade program (EB-2016-0300).
- Participated as an intervenor and party to the settlement of Union Gas' application for distribution, transmission and storage of natural gas rates (EB-2016-0245).
- Participated in the hearing regarding Hydro One's application to the OEB to purchase Great Lakes Power Transmission (EB-2016-0050).

- Participated in the hearing and settlement conference in the IESO's application to the OEB to set its 2016 fees (EB-2015-0275).
- Participated in the hearing regarding Union and Enbridge's application for pre-approval of the cost consequences of a 15-year transportation contact (EB-2015-0166/EB-2015-0175). Drafted the final argument, interrogatories and led cross examination.
- Participated in the hearing to set Hydro One's 2015-2019 distribution rates (EB-2013-0416/EB-2015-0079). Transmission Facility Review and Pricing Proceeding Support

**Research and Publications**

*Academic*

- Ontario's Electricity Market Woes: How Did We Get Here and Where are We Going, Energy Regulation Quarterly, July 2020

*Op-eds*

- Another megaproject pushing public utilities to the brink, *The Telegram*, September 30, 2017
- Government's mega utility projects spell mega-ruin, *Financial Post*, September 26, 2017
- Megaprojects like Site C bankrupt power utilities, *Vancouver Sun*, September 18, 2017
- Ontario's conservation program another corporate welfare handout, *Financial Post*, August 3, 2017
- Ontario's public power failure redux, *QP Briefing*, June 22, 2017
- How Queen's Park broke Ontario's provincial electricity sector, *Financial Post*, April 12, 2017
- Looking to lower Ontario power rates? Start with Pickering, where $550 million will be wastefully spent, *Financial Post*, March 29, 2017
- No prizes for guessing who's really to blame for Hydro One's soaring rates, *Financial Post*, January 6, 2017
- This time is different: OPG says its megaproject not like the others, *Toronto Star*, October 11, 2016
- How Ontario's 1 per cent can do its share to reduce fuel poverty, *Financial Post*, August 16, 2016
- A new debt retirement charge for Ontario electricity customers, *Financial Post*, April 27, 2016
- Queen's Park the biggest winner with cap and trade, *Hamilton Spectator*, March 23, 2016
- Ontario electricity rates fastest rising in North America, *Toronto Sun*, March 2, 2016
- Queen's Park moves to silence dissent on electricity, *Toronto Star*, January 4, 2016
- Ratepayers on the hook for Hydro, *Winnipeg Free Press*, December 23, 2015
- The Hydro One sale's upsides, *Financial Post*, November 5, 2015
- Debt, subterfuge will cost B.C. Hydro ratepayers, *The Times Colonist*, October 24, 2015
- Privatization perks, *Financial Post*, September 22, 2015

- A $2.6-billion stimulus for Ontario, *Financial Post*, August 12, 2015
- Much needed reforms could focus on Hydro One employees' pensions, *Financial Post*, April 24, 2015
- Achtung, Ontario! Renewables are a money pit, *Financial Post*, August 12, 2014
- While Canadians endured hardships during recent storms, customers in UK got compensated, *Financial Post*, January 7, 2014
- Why China's renewables industry is headed for collapse, *Financial Post*, December 10, 2013

*Notable Media Appearances*

- The Agenda,
- CBC, "On the Money"
- Many other TV and radio appearances, including BNN and CBC radio

*Reports*

- Multiple Monitoring reports by the Ontario Market Surveillance Panel
- How Megaprojects Bankrupt Public Utilities and Leave Regulators in the Dark, 2017
- Power Exports at What Cost? 2016
- Getting Zapped: Ontario's Electricity Prices Increasing Faster Than Anywhere Else, 2016
- Gone Too Far: Soaring Hydro Bills Offset Conservation and Hurt Conservers Most, 2015
- Falls Flat: Comparing the TTC's Fare Policy to Other Transit Agencies, 2015
- Corporate Welfare Goes Green in Ontario, 2014
- Toronto's Suburban Relief Line. 2014

*Presentations*

- Presentation to the Standing Committee on Natural Resources in the House of Commons
- Market Monitor conference Austin Texas, 2029, Reviewing Ontario's Industrial Conservation Initiative
- Presentation to Northwind conference, 2018, How megaprojects bankrupt utilities.

**Work Experience**

*Senior Manager – Markets and Regulatory, Power Advisory, March 2020 – Present*

- Collaborate on Power Advisory's market and regulatory work for clients across North American jurisdictions.
- Particular expertise on the interaction between rate regulation and wholesale markets.
- Lead on Power Advisory's custom electricity price forecasts for Ontario
- Provide detailed analysis and modelling for a range of market participants in Ontario and other wholesale markets
- *Senior Analyst* – Markets Assessment and Compliance Division (MACD), the Independent Electricity System Operator**,** September 2018 – February 2020

- Senior Analyst with the Market Assessment Unit (MAU) within Market Assessment and Compliance Division (MACD).
- Oversaw research and investigations in Ontario's electricity market for the Market Surveillance Panel (MSP).
- Wrote and performed research for semi-annual monitoring reports published by the MSP.
- Provided analysis and research in public forums – both internally to MACD and to external stakeholders.
- Gained an in-depth knowledge of both the Ontario wholesale electricity market and markets in other jurisdictions.

*Economist and Executive Director* – Consumer Policy Institute, July 2013 – September 2018

- Oversaw research activities for the Consumer Policy Institute.
- Was a consultant for regulatory hearings at the Ontario Energy Board (OEB), in which I reviewed and commented on evidence presented by public utilities. I have submitted multiple papers to the OEB on a range of topics, such as pension reform, revenue decoupling, natural gas expansion and distributor rate applications. I have cross examined many witnesses and executives regarding energy issues in Ontario.
- Have appeared numerous times on both television and radio to discuss energy and other economic topics. My research has been quoted extensively by experts, lawmakers and the media
- Write analysis reports and articles for media outlets. I have several recent opinion pieces published in national newspapers.
- Oversee the work of interns and other employees at Energy Probe Research Foundation.

*Online Reporter, Commentator and Editor – Business New Network, December 2010 – July 2013*

- Wrote and edited all content published on BNN.ca, with a particular focus on economic issues.
- Attended lockups for budgets and interest rate announcements and published breaking stories.
- Notable articles include: "Canada's lost decade in manufacturing," "The rise and fall of
- Canadian exporters" and "More Fed action likely, but will it work?"
- Managed the outlet's website and came up with ideas for new columns and ways to present our content.
- Interviewed leading analysts, officials and other commentators on economic, political and business issues.

*Researcher and Policy Consultant – Energy Probe Research Foundation, April 2009 – December*
*2010*

- Performed economic, financial and political research on economic, policy and energy issues.

- In-house specialist on European carbon credit markets. I helped build and maintain the first, and only (at the time), online database of carbon credit projects. I was often called upon to explain the carbon credit market to reporters, other policy groups and policy makers.
- Engaged with policy makers through interviews and reports.

*Freelance Writer/Reporter – January 2009 – Present*

- Wrote articles for a variety of publications, including: ***Washington Post**, **China Daily, BlogTO, Building.ca*** and other trade magazines. Articles often provided commentary on major issues.
- Research involved searching through government databases, company reports, interviewing specialists and conducting other studies.

*Producer, Writer – Brookshire Media, Toronto ON, January 2008 – December 2008*

- Reported on and investigated financial markets -- including commodity markets, equity markets and currency markets.
- Wrote and edited articles on both financial markets and international politics.

*Editor – Corp Tax, Chicago, IL, September 2006 to February 2007*

- Wrote internal reports.

  Explained tax policies and forms to clients.

## APPENDIX F: CV OF MICHAEL KILLEAVY


### Michael Killeavy
Commercial Director

### Power Advisory LLC
55 University Avenue
Suite 605, P.O. Box 32
Toronto, ON M5J 2H7
Cell: (416) 528-6365
mkilleavy@poweradvisoryllc.com


## SUMMARY

A senior electricity sector consultant with over thirty years of experience in energy and infrastructure sector. Experienced in power and infrastructure procurement, project management, project valuation, commercial negotiations, and project oversight.

### Professional History

Power Advisory LLC (2018 to Present)
Independent Electricity System Operator (2015 to 2018)
Ontario Power Authority (2009 to 2015)
Knowles Consultancy Services Inc. (2000 to 2009)
High-Point Rendel Canada (1997 to 2000)
Regional Municipality of Niagara (1990 to 1997)
Trow Consulting Engineers Ltd. (1985 to 1990)

### Education

Nottingham Law School, LL.B., 2006
McMaster University, MBA, 1995
McMaster University, M. Eng., 1985
University of Toronto, B.A.Sc., 1983

## PROFESSIONAL EXPERIENCE

### Power and Infrastructure Procurement

- Process Advisor to the Ministry of Energy in Ontario for the Renewable Energy Supply (RES) I, RES II, and 2500 MW Clean Energy Supply (CES) RFPs in 2003 and 2004. Advised on process design and monitored process from pre-qualification of proponents through the RFQ process, launch of the RFP, through the evaluation process up to the award of the contracts. Provided advice on the conduct of the procurement process directly to the Assistant Deputy Minister of Energy responsible for the three procurements. Participated in debriefing unsuccessful proponents. Advised on disclosure of the information pertaining to the procurement to the media. Participated in debriefing unsuccessful proponents to the RFP.
- Process Advisor to the Ontario Power Authority (OPA) for the Greater Toronto Area (GTA) West RFP in 2006. Advised on process design and monitored process from launch of the RFP, through the evaluation process up to the award of the contract.

- Process Advisor to the OPA for the South West GTA RFP in 2008 and 2009. Advised on process design and monitored process from launch of the RFP, through the evaluation process up to the award of the contracts.
- Process Advisor to the OPA for Combined Heat and Power (CHP) I RFP, CHP II RFP, and Renewable CHP III RFP, 2006 to 2009. Advised on process design and monitored process from launch of the RFP, through the evaluation process up to the award of the contracts.
- Process Advisor to the OPA for the Northern York Region Peaking Plant RFP in 2008. Advised on process design and monitored process from issuance of the RFQ to qualify proponents to the RFP, launch of the RFP, through the evaluation process up to the award of the contract.
- Process Advisor to SaskPower for the Peaking Plant RFP and Mid to Baseload RFP for simple cycle and combined cycle CCGT plants, respectively. Advised on process design and monitored process from prequalification of RFP proponents through the RFQ process, launch of the RFP, through the evaluation process up to the award of the contracts. Briefed SaskPower President and executive team on issues pertaining to the procurement. Participated in debriefing unsuccessful proponents.
- Process Advisor to Infrastructure Ontario for New Build Nuclear RFP in 2008 and 2009. This was a very high profile and politically sensitive procurement. Advised on process design and monitored process from launch of the RFP, through the evaluation process up to the award of the contracts. Regularly briefed Infrastructure Ontario President, and Minister of Energy and Infrastructure.
- Process Advisor to Infrastructure Ontario for six hospital and four courthouse RFQs and RFPs. Advised on process design and monitored process from launch of the RFQ process to prequalify proponents to the RFP, issuance of the RFP to pre-qualified proponents, through the evaluation process up to the award of the contracts.
- Process Advisor to the Ministry of Energy for the RFQ to select qualified vendors for its Advanced Metering Initiative (AMI). The objective of the RFQ was to identify a number of vendors from whom smart meters could be procured and also procurement of installation services. Advised on process design and monitored process from launch of the RFQ process and through the evaluation process up to the establishment of the pre-qualified vendor list.

### Commercial Negotiation

- Negotiated restatement and amendment of the Bruce Power Refurbishment Implementation Agreement (BPRIA) to include all CANDU nuclear reactors at the Bruce Nuclear Generation Station. Responsible for initiating commercial discussions, development of term sheet, drafting of the final amended and restated BPRIA (ARBPRIA). This commercial deal involved approximately $13 billion worth of new investment in refurbishing six nuclear reactors. Negotiations took approximately two years to complete.
- Negotiated relocation of two CCGT plants (300 MW plant and 900 MW plant), which included negotiations over the siting of the relocated plants, commercial terms to the amended contract agreements, and settling disputes with a lender who provided construction financing to one of the projects. Responsible for developing financial models for each project to assist in the commercial negotiations. These negotiations took approximately two years to conclude.
- Negotiated amended contract terms with OPA wind and solar energy contract counterparties as a result of an IESO market rule change making transmission-connected wind and solar generators variable generators (capable of being dispatch down to alleviate surplus baseload generation) rather than intermittent generators that would self-schedule.
- Negotiated amended contract terms for 50 gas-fired generators as a result of the implementation of a provincial cap and trade scheme to price carbon emissions.
- Negotiated numerous settlements pertaining to contractual disputes between generators and the OPA/IESO. These disputes pertained primarily to claims for addition compensation under the contracts or extension in time to develop generation facilities.

- Negotiated resolution of a shareholder dispute between three partners in a privatized highway in New Brunswick, Canada.

## Project Management

- Managed the development and implementation of an IT-based contract management system to track power developer deliverables for the portfolio of OPA generation contracts. The growth in Feed-in Tariff contracts in Ontario was the primary driver to initiate this project. The project team consisted of internal Contract Management and Procurement resources, internal and external counsel, and external IT consultants to document Contract Management business processes, prepare a data model for the various types of contracts, capture of functional and non-functional requirements, and development of the RFP to select a software vendor. The implementation phase of this project consisted of overseeing the software developer customizing the solution to OPA needs.
- Managed the project to develop the approach to amending contracts to reflect the cost of carbon for IESO gas-fired generation contracts. This project was established as a prelude to commercial negotiations in order to develop a framework for entering these negotiations. This included retaining technical, economic and legal consultants to augment the internal team.
- Managed the project tasked with evaluating replacement of nuclear fuel at the Bruce Nuclear Generating Station. Canadian Nuclear Safety Commission regulatory changes meant that use of low void reactivity fuel (LVRF) at Bruce Nuclear Generating Station could be replaced. The project tasked with conducting the technical and financial analysis for various replacement fuels.
- Led the project team tasked with developing the program rules and funding agreement for the IESO Energy Partnerships Program, which as designed to provide seed funding to community and aboriginal groups to undertake Feed-in Tariff projects.
- Led project team tasked with resolving the Metered Market Participant issue on RES I and RES II Contracts. Prior to the OPA IESO merger the OPA had been MMP for several renewables contracts. Post-merger this role has to be divested to generators so that the IESO wasn't on both sides of market transactions.
- Led project team tasked with implementing common market and contract-based settlement post IESO/OPA merger in 2015.
- Led project team providing litigation support for a dispute between the EPC contractor and owner of a CCGT plant in Ireland.
- Managed numerous heavy civil engineering projects, including hydroelectric and wind farm projects.

## Project Valuation

- Prepared valuation estimates for damages calculations associated with several lawsuits for FIT PPA-style contracts in Ontario. This involved modelling PPA revenues and costs to predict cash flows and calculate the net present value of after-tax cash flows. The overall viability of projects were assessed by reviewing the status of project permitting efforts and financial commitments, the major provisions of power purchase agreements and steam purchase agreements.
- Developed financial models used to support commercial negotiations for amending gas-fired generation contracts. This involved preparing a spreadsheet model to replicate the deemed dispatch logic used to impute revenues in the OPA gas-fired generation contracts.
- Prepared the cost-benefit analysis to assess the feasibility of life extensions for Bruce Nuclear Generating Station. This involved comparing CAPEX and OPEX for life extension option to replacing the nuclear units with gas-fired generation.
- Developed analysis to assess the value of off-ramps in the ARBPRIA. The analysis used a real options analysis approach to assess the value in being able to take units out of the contract at future dates if certain threshold conditions were met.

**Project Oversight**

- Developed contract management processes to monitor developer deliverables for the OPA/IESO portfolio of contracts. This consisted of developing a contract management manual and business use cases for each process to ensure consistent treatment of the wide variety and large number of contracts.
- Developed annual compliance audit program for renewable generators. This involved establishing audit program objectives related to key contract parameters (connection point, contracted capacity, renewable fuel type, etc.) and domestic content (each FIT contract needed to have a certain percentage of domestic content). The program was delivered by a roster of independent auditors whose services were procured by means of an RFP. The audit results were reported directly to the OPA/IESO board of directors.
- Developed annual summer capacity check test program for gas-fired generators. This involved finalizing the capacity check test protocols for each gas-fired facility and then monitoring the test protocol with in-house staff and an independent third-party engineer.
- Developed process for handling developer force majeure claims requesting additional time to construct their facilities.

## APPENDIX G: CV OF JASON CHEE-ALOY

Jason Chee-Aloy

Managing Director

**Power Advisory LLC**
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Toronto, ON M5J 2H7
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jchee-aloy@poweradvisoryllc.com

### SUMMARY

Mr. Chee-Aloy is a professional with over 25 years of expertise in electricity and natural gas market analysis, policy development and market design, project development, resource and infrastructure planning, and stakeholder consultation and engagement. He has worked as an energy economist with a strong analytical foundation and understanding of commodity pricing, market design, contract design, industry restructuring, policy development, business strategy, industry governance, and planning and development of electricity infrastructure.

Mr. Chee-Aloy joined Power Advisory after being the Director of Generation Procurement at the Ontario Power Authority (OPA), where he was responsible for procuring over 15,000 MW of generation. He led the development, consultation and implementation of North America's first comprehensive Renewable Energy Feed-in Tariff (FIT) Program. Prior to joining the OPA, he worked for the Independent Electricity System Operator (IESO) where he was actively involved with restructuring Ontario's electricity sector by leading key areas of market design.

Mr. Chee-Aloy is acting for multiple generator, transmitter, distributor, financial institution, and regulatory agency clients regarding numerous areas of, but not limited to: policy design; market design; contract design; contract negotiation; project development; market analysis; business strategy; regulatory affairs; power system planning and resource assessments; etc.

### Professional History

Ontario Power Authority
Independent Electricity System Operator
Ontario Ministry of Energy, Science and Technology
Canadian Enerdata Limited

### Education

York University, MA, Economics, 1996
University of Toronto, 1995

## PROFESSIONAL EXPERIENCE

### Generation Project Development and Operations, and Project Acquisition

- Assisted multiple generation clients regarding their participation in the Ontario and Alberta wholesale electricity markets and resolution of contract issues. Work with these generators includes strategy and solutions regarding analysis of impacts to changes to wholesale market rules and analysis of impacts to changes in the market design, including implications on their long-term contracts.
- Assisted multiple generation developers towards commercial operation of their projects under long-term contracts. Work with these developers includes strategy and solutions regarding analysis of permitting and approvals, provincial content requirements, connection requirements, financing and future operations in the wholesale power market to optimize operations and maximize revenues in the wholesale market and under long-term contracts.
- For multiple renewable generation clients, advised and represented their interests towards developing their generation projects, including work in areas dealing with long-term contracts, connection impact assessments, system impact assessments, and financial plans.
- Worked with lenders and financiers providing market intelligence, market forecasts, and strategic advice regarding investment in generation projects.
- Worked with owners of existing generation facilities, equity providers, and developers to value projects for purposes of acquisitions. This work involves assessment of wholesale electricity markets and valuation of specific generation resources.

### Wholesale Electricity Market Design and Development

- Acting for multiple generator, energy storage provider, transmission, Local Distribution Companies (LDCs) regarding the IESO's Market Renewal Program, including planned development of Locational Marginal Prices (LMPs), Day-Ahead Market (DAM), Enhanced Real-Time Unit Commitment (ERUC), and Incremental Capacity Auctions (ICAs)
- Acted for the Ontario IESO as the facilitator/consultant for the IESO's Electricity Market Forum. This work involved identification and sequencing the major initiatives and recommendations required to evolve Ontario's electricity sector. The initiatives and recommendations included: review of wholesale spot pricing, costs to customers and cost allocation; review of long-term contracts to ensure alignment with the wholesale market; review of regulated rate design regarding its effect and integration with the wholesale market; increasing demand-side participation in the wholesale spot market; review and assess the need for new ancillary services in light of Ontario's changing supply mix; review of the two-schedule dispatch system within the wholesale market; and review of the framework for scheduling intertie transactions in the wholesale market.
- For gas-fired generator clients, advised how these facilities can meet power system needs within wholesale electricity markets and operate more efficiently given changes fuel supply, utilization of wholesale market programs, and requirements for day-ahead commitment programs.
- For transmission clients, advised how new regulated or merchant transmission lines may be developed within various electricity markets along with specific regulatory requirements and policies.
- For multiple renewable generation clients, advised and represented their interests regarding the integration of variable (i.e., wind and solar) generation within wholesale electricity markets. The work required intimate and technical knowledge of the operations on wholesale markets and the technical capabilities of generation facilities regarding how generation units are scheduled and dispatched, how prices are set, and the mechanisms for compensation for production of energy output.
- For multiple clients, advised on transmission rights within wholesale electricity markets regarding rules and protocols relating to intertie transactions regarding scheduling transactions and associated risks dealing with congestion rents, failed transactions, etc.

- While at the IESO, was Project Manager of Resource Adequacy and developed and delivered high-level design, detailed design, and draft market rules for a centralized forward Capacity Market, and chaired the Long-Term Resource Adequacy Working Group comprising over 20 electricity sector stakeholders.
- For the IESO, implemented short-term resource adequacy mechanisms through the Hour-Ahead Dispatchable Load program and Replacement Generation to Support Planned Outages in 2003 and 2004.
- Developed and drafted over 50 IESO Market Rule amendments, including applicable quantitative assessments, mainly regarding market surveillance, compliance, reliability, scheduling, dispatch and pricing rules, and settlements, therefore having a very strong understanding and knowledge on how the IESO-Administered Markets operate and in particular how the dispatch and pricing algorithms work.
- Developed business processes, developed data requirements, and reviewed applicable Market Rules (e.g., local market power rules) for the Market Assessment Unit.

### Generation and Transmission Procurement and Contracting

- Acted for the Government of Alberta in development and administration of the Solar Procurement
- Acted for multiple gas-fired generators regarding contract amendments resulting from the forthcoming Ontario cap-and-trade system.
- Acted for variable generators through market analysis, contract analysis, financial analysis, and led contract negotiations before the OPA and IESO to amend long-term contracts to address potential IESO economic curtailment of energy production from these generators resulting from the integration of these generators into the real-time scheduling and dispatch process within Ontario's wholesale energy market.
- Acted for multiple Non-Utility Generator (NUG) facilities and other generator clients through market analysis, contract analysis, and financial analysis, and successfully led contract negotiations for existing and new generation facilities resulting from the expiration of existing Contracts towards execution of new long-term contracts with the IESO.
- Responsible for the delivery of the design, management and execution of all generation procurement processes and contracts for development of electricity supply resources while at the OPA. This included contracting for over 15,000 MW of generation capacity (including some demand-response), including combined cycle gas turbine facilities, simple cycle gas turbine facilities, combined heat and power facilities, waterpower facilities, bio-energy facilities, wind power (on- and off-shore) facilities, solar PV facilities and energy-from-waste facilities ranging in size from under 10 kW to over 900 MW through competitive and standard offer procurements and sole source negotiations. The development of procurement processes and long-term contracts needed to necessarily consider the integration of these generation projects into the wholesale market.
- Managed over 80 staff, developed and successfully implemented North America's first large FIT procurement program for renewable electricity supply resources. To date, over 20,000 applications totaling over 18,000 MW from prospective generation projects have been submitted to the Ontario Power Authority, with over 2,500 MW successfully contracted. In addition, chaired the Renewable Energy Supply Integration Team (RESIT) comprising of Ontario agencies and Government. This Team also held responsibility to implementing the FIT Program.

- Chaired the RESIT that delivered recommendations to the Minister of Energy for development of the Green Energy Act and the FIT Program. Delivered a consensus document assessed and recommended changes to Ontario Energy Board (OEB) Transmission and Distribution System Codes, regulations and legislation, in addition to the roles and responsibilities of the OPA, IESO, transmitters, OEB and utilities towards ensuring timely development of renewable generation. Senior staff from the IESO, OPA, Hydro One, OEB and the Ministry of Energy comprised the RESIT while Executives from IESO, OPA, OEB and Hydro One frequently attended these meetings.
- Advised multiple clients regarding transmission development opportunities and power system needs within various electricity markets across North America.
- Acted for a U.S. transmission developer and operator regarding the development of a merchant transmission project that will connect Ontario to Pennsylvania through market analysis, regulatory support, business strategy, and contract development support.
- Advised the Alberta Electricity System Operator (AESO) regarding development of their present transmission procurement process by researching and reviewing transmission procurement processes from Ontario and Texas.
- Advised multiple renewable generation developers regarding forthcoming participation within the AESO's renewable generation procuring and contracting initiatives under the Renewable Electricity Program.

### Power System Planning and Infrastructure Assessment

- For multiple generator and trade associations, assessed and optimized generation resource options and likely solutions to be developed to meet future power system needs, and developed business strategies and strategic plans for these clients to execute towards increasing their market share by increasing their development pipeline of projects.
- While at the OPA, was a member of the OPA's Integrated Power System Plan (IPSP) Steering Committee that was responsible for the development and review the 20-year IPSP, developed strategy for the regulatory filing and OEB proceeding, was an expert witness for the interfaces between the generation and conservation and demand management (CDM) resource requirements specified within the IPSP and the applicable procurement processes that would be used to contract for these generation and CDM resources.

### Wholesale Electricity Market Surveillance and Compliance

- While at the IESO, developed and delivered the IESO market rules and market manuals relating to the market surveillance and compliance activities, which included extensive research of other ISOs/RTOs regarding their market surveillance and compliance rules, protocols, and business practices.
- While at the IESO, worked with system venders to determine, develop, and implement the data requirements and market monitoring indices to be used by the IESO’s Market Assessment and Compliance Division (MACD) within their day-to-day operations and investigations.
- While at the IESO, worked with the OEB and federal Competition Bureau to develop and deliver the first Memorandum of Understanding between these three organizations regarding their jurisdictional roles and responsibilities regarding the assessment, determinations, and investigations relating to gaming, market power, and anti-competitive behavior.
- For the Independent Power Producers Society of Alberta (IPPSA), assisted with research, analysis, and recommendations regarding potential changes to the Alberta Market Surveillance Administrator’s assessment of market harm.

- For multiple generator clients, providing on-going research, analysis, and recommendations relating to their compliance with the IESO market rules and applicable IESO market manuals regarding offer strategies with respect to dispatch within the IESO-Administered Markets and regarding import and export transactions.

## Policy Development

- For the Association of Power Producers of Ontario (APPrO) and the Canadian Solar Industries Association (CanSIA), member of the OEB's Standby Rates Working Group that commented on potential policy direction for standby rates, including analysis and commentary on revenue decoupling
- For multiple generation and association clients, using the supply mix and CDM scenarios and targets conveyed in the above point to assess and analyze the Ontario Government's present review of the LTEP, and developing policy positions for these clients regarding forthcoming changes to the LTEP.
- For multiple generation and association clients, assessing and analyzing applicable changes to CDM policies and targets as proposed in the July 2013 Ontario Government's conservation white paper, and developing policy positions for these clients.
- For multiple generation and association clients, assessing and analyzing a potential framework for regional planning and siting of large energy infrastructure projects, as the IESO and OPA have been directed by the Minster of Energy to provide recommendations by August 1, 2013, and developing policy positions for these clients.
- For multiple generation and association clients, assessing and analyzing potential changes to the procurement and contracting of renewable generation projects outside of the FIT Program though an OPA to-be-developed competitive procurement process, and developing recommendations on the design of a competitive procurement process for these clients.
- Advised APPrO on the structure and design of the Ontario electricity market from policy, market structure and market design points of view (including SWOT analysis of APPrO vis-à-vis its position in Ontario's electricity market and with other energy associations) and facilitated meeting of the APPrO Board of Directors.
- Advised the Ontario Energy Association on various policy developments relating to the Green Energy and Green Economy Act, 2009, OEB's Renewed Regulatory Framework, etc.

## Stakeholder Consultation and Engagement

- From November 2013 to April 2014, Jason Chee-Aloy was the Power Advisory lead acting for the OEB in reviewing the OEB's governance and processes regarding their policy stakeholder consultation framework. The OEB's policy stakeholder consultation framework was assessed relative to policy stakeholder consultation frameworks of other energy and non-energy North American regulators, interviews were confidentially conducted with stakeholders that typically participate in the OEB's policy stakeholder consultation framework, and recommendations to changes of the OEB's policy stakeholder consultation framework were made directly to the Chair of the OEB.
- In 2011, Power Advisory was appointed as the Government of Nova Scotia's Renewable Electricity Administrator (REA) to design and implement a competitive procurement process to contract for new renewable energy supply. As part of the REA's scope of work, Power Advisory designed and successfully implemented a robust stakeholder consultation and engagement for the procurement process which included setting clear goals and objectives for the competitive procurement process, scheduled and led meetings with stakeholders (including Aboriginal peoples), consulted and engaged stakeholders in the design of the Request for Proposal and Contract documents, regular reports back to the Government of Nova Scotia, and successful conclusion of the procurement process by execution of contracts for new renewable energy supply in 2012. Jason Chee-Aloy was a key part of Power Advisory's team that designed the stakeholder consultation and engagement process.

- In 2012, Jason Chee-Aloy acted for the IESO as the consultant and facilitator for the Electricity Market Forum. In addition to be the technical consultant and subject matter expert, this engagement comprised of facilitating bi-weekly meetings for nearly a year with senior stakeholders representing all segments of Ontario's electricity market.
- Prior to joining Power Advisory in 2010, Jason Chee-Aloy led the design and facilitation of stakeholder consultation and engagement initiatives as Director of Generation Procurement at the OPA (2005 to 2010), and as a Project Manager in the IESO's Market Evolution Program initiative (2003 to 2005). While at the OPA, Jason Chee-Aloy designed and chaired the Renewable Energy Supply Integration Team which was a form of stakeholder consultation with the goals and objectives of the OPA, OEB, IESO and Hydro One providing technical advice directly to the Minister of Energy and Infrastructure on the development of the Green Energy and Green Economy Act (2009) and the Feed-in Tariff (FIT) Program. Various Executives and senior staff from the OPA, OEB, IESO and Hydro One comprised the members of Renewable Energy Supply Integration Team. In part resulting from input from the Renewable Energy Supply Integration Team, Jason Chee-Aloy led the development of the stakeholder consultation and engagement of the design and implementation of the FIT Program. He led all stakeholder consultation and engagement meetings over several months where at times more than 400 stakeholders attended in person, by phone, or by web conferencing.

## Expert Testimony

- Retailed by Stikeman Elliott LLP on behalf of three Quebec-based hydroelectric generators regarding renegotiation of Power Purchase Agreements (PPAs) with Hydro-Quebec, including development of two expert reports filed within the arbitration proceedings, including expert testimony and cross-examination (2016)
- Before the OEB, began testimony for OPA regarding scope of Procurement Process within OEB proceeding to render decision on OPA's IPSP and Procurement Process – proceeding terminated in late 2008 (2008)
- Before the OEB, for Ontario Power Authority, testified to sections of the OPA Business Plan regarding organization and management of generation procurement and contract management business units (2006)

## Selected Speaking Engagements

- Energy Storage Canada, Optimizing Our Energy Grid, Toronto, October 2024
- Association of Power Producers of Ontario / Ontario Energy Association, Annual Conference, Toronto, September 2024
- National Electricity Roundtable, Getting to Net-Zero by 2050, Ottawa, November 2023
- Canadian Bar Association, Environmental, Energy and Resources Law Summit, Renewable and Distributed Energy: Legal Updates and Opportunities, Ottawa, May 2023
- Ontario Energy Association, Speaker Series – A Proposal for Clean Energy Corporate Power Purchase Agreements in Ontario, Toronto, April 2023
- Association of Power Producers of Ontario / Ontario Energy Association, Ontario Energy Conference, Toronto, November 2022
- Canadian Renewable Energy Association, Annual Conference – Electricity Transformation Canada, Toronto, October 2022, October 2021
- Energy Disruptors, Unite Energy Summit, Calgary, September 2022
- Association of Power Producers of Ontario / Ontario Energy Association, Navigating to Net-Zero, Toronto, September 2022

- Bank of America Securities, April 2022, April 2021, web conference - Canadian Power and Utilities Conference
- Independent Power Producers Society of Alberta, Get to Net, March 2022
- Davies Ward Phillips & Vineberg LLP, Davies Academy, Is Canada's Electricity Sector Ready for a Zero-Carbon Future?, Toronto, January 2022
- Independent Power Producers Society of Alberta, Annual Conference, Banff, November 2021, March 2019 and March 2017
- Association of Power Producers of Ontario, Annual Conference, Toronto, November 2021, December 2020, November 2019, November 2018, November 2017, November 2016, November 2015, November 2014, November 2013, November 2012, November 2011, November 2010, November 2009, November 2008, November 2007, November 2006, November 2003
- Canadian Renewable Energy Association, Annual Conference – Electricity Transformation Canada, Toronto, October 2021
- Ontario Waterpower Association, Annual Conference, Niagara Falls, May 2021, October 2019, October 2018, October 2017, October 2013, October 2013, December 2012, December 2011
- Canadian Bar Association, May 2021, web conference - Environmental, Energy & Resources Law Summit, The Ins and Outs of Climate Change, Carbon and Renewables, State of Play in Renewable and Distributed Energy Across Canada
- Canadian Renewable Energy Association, February 2021, web conference - What's Next for Corporate Power Purchase Agreements and Renewables in Canada?
- Maritimes Energy Association AGM, January 2021, web conference - Canadian Energy Transition
- Electricity Invitational Forum, Cambridge, January 2021, January 2020, January 2019, January 2018, January 2011
- EUCI, web conference - Capacity Markets Pricing and Policy Summit, December 2020
- Canadian Renewable Energy Association, Toronto, November 2020, Canadian Renewable Energy Forum: Wind. Solar. Storage.
- Ontario Energy Association, Toronto, October 2020, Corporate PPAs - Potential Opportunities for Energy Buyers/Sellers in Canada
- Business Renewables Centre Canada, October 2020, web conference - Understanding the Corporate PPA Landscape Across Canada: A Jurisdictional Review
- DeMarco Allen LLP, Strategy Session, October 2020
- Ontario Energy Association, October 2020, web conference - Corporate PPAs: Potential Opportunities for Energy Buyers/Sellers in Canada
- Business Renewables Centre Canada, June 2020, web conference - Outlook for Alberta's Electricity Market Focusing on PPAs
- Canadian Power Finance Conference, Toronto, January 2020, January 2019, January 2018, January 2015, January 2012, January 2011
- Canadian Wind Energy Association, Annual Conference, Calgary, October 2019, October 2018, Toronto, October 2017, October 2016, October 2015
- Ontario Energy Association, Annual Conference, Toronto, September 2019, September 2018, September 2017, September 2016, September 2015, September 2014, September 2013, Niagara Falls, September 2012
- Proximo, Canadian Power and Renewables Exchange, Toronto, June 2019
- Ontario Energy Association, Speaker Series, Toronto, May 2019

- Canadian Wind Energy Association, Spring Forum, Banff, April 2019
- Bank of America Merrill Lynch, 2019 Canadian Utilities Day, New York, April 2019
- AQPER 2019 Symposium, Quebec City, February 2019
- Canadian Solar Industry Association, Solar Ontario, Toronto, October 2018, Ottawa, May 2014, Niagara Falls, May 2013
- Energy Storage Canada, Annual Conference, Toronto, September 2018, September 2017
- Ontario Energy Association, Conversations That Matter, Toronto, June 2018
- Canadian Electricity Association, Transmission and Distribution Council, Calgary, May 2018
- Canadian Electricity Association, Pre-CAMPUT Workshop, Toronto, May 2018
- Electricity Distributors Association, ENERCOM, Toronto, March 2018
- Energy Law Forum, Vancouver, May 2017
- U.S./Canada Cross-Border Power Summit, Boston, April 2016, April 2015
- UBS, Canadian Power Markets, New York, July 2015
- UBS, Canadian Power Markets, Toronto, June 2015
- Aird & Berlis LLP, The Impact of Capacity Market on LDCs, Toronto, May 2015
- Mindfirst Lunch Seminar: Ontario Capacity Auction - Analysis of Feasibility and Criteria for Design Elements, Toronto, May 2015
- Ontario FIT and Renewable Energy Forum, Toronto, March 2015
- Canadian Wind Energy Association Operations & Maintenance Summit, Toronto, February 2015
- Canadian Solar Industry Association, Annual Conference, Toronto, December 2014, December 2013, December 2012, December 2011, December 2010 and December 2009
- EUCI, Canada Energy Storage Summit, Toronto, November 2014
- UBS, Ontario Power Markets, New York, November 2014
- Ontario Power, Examining the Future Structure of Ontario's Electricity Market: Should Ontario Incorporate a Capacity Market or Alternative Structure Framework, Toronto, April 2014
- EUCI, Securing Ontario's Distribution Grid of the Future, Toronto, September 2013
- TD Securities, Canadian Clean Power Forum, Toronto, September 2013
- TREC Education, Toronto, June 2013
- FIT Forum, Toronto, April 2013, April 2012
- Nuclear Symposium, Toronto, May 2012
- TD Securities, The Future of Ontario's Power Sector, Toronto, April 2012
- Ontario Power Perspectives, Toronto, April 2012
- Ontario Energy Association Speaker Series - FIT and the Provincial Budget: What do they mean for Ontario's Electricity Sector, Toronto, April 2012
- Energy Contracts, Calgary, March 2012
- Environmental Law Forum, Cambridge, January 2012
- Capstone Infrastructure Corporation, Investor Day, Toronto, December 2011
- Canadian Projects and Money, Toronto, June 2011

- Ontario's Feed-in Tariff, Toronto, June 2011
- Photon's Solar Electric Utility Conference, San Francisco, February 2011
- Ontario Solar Network, Solar Summit, Toronto, February 2011
- Credit Suisse Alternative Energy Conference, Washington, June 2010
- Transmission and Integrating New Power into the Grid, Calgary, April 2010
- Feed-in Tariff: Another Tool for Meeting RPS, San Francisco, February 2010
- BC Power, Vancouver, January 2010
- Infrastructure Renewal, Toronto, October 2009
- Green Energy Week, Toronto, September 2009
- Ontario Waterpower Association Executive Dialogue, May 2009, May 2008, October 2008
- GasFair and PowerFair, Toronto, April 2008, May 2007, April 2006
- Eastern Canadian Power and Renewables Finance Forum, Toronto, February 2008
- Quebec Forum on Electricity, Montreal, April 2007
- Energy Contracts, Toronto, March 2007, November 2003
- Power On, Toronto, October 2006
- Generation Adequacy in Ontario, Toronto, April 2006, March 2005, April 2004
- Installed Capacity Markets - Designing and Implementing Installed Capacity Markets, Boston, May 2004
- Ontario Electricity Conservation and Supply Task Force, September 2003, July 2003

## APPENDIX H: OEB FORMS

### FORM A

Proceeding: EB-2024-0331

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is Brady Yauch (*name)*. I live at Toronto (*city)*, in the province (*province/state*) of Ontario .

2. I have been engaged by or on behalf of Borden Ladner Gervais LLP (*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:
   (a) to provide opinion evidence that is fair, objective and non-partisan;
   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and
   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date December 17, 2024

*Signature*

**FORM A**

Proceeding:..........................

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is JASON CHEE-ALOY (*name*). I live at TORONTO (*city*), in the PROVINCE (*province/state*) of ONTARIO .

2. I have been engaged by or on behalf of BORDEN LADNER GERVAIS LLP (*name of party/parties*) to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

   (a) to provide opinion evidence that is fair, objective and non-partisan;

   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and

   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date 12/18/24

*Signature*

**FORM A**

Proceeding:EB-2024-0331

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is Michael Killeavy. I live at *34 Chester Street*, in the Town of Oakville of Ontario.

2. I have been engaged by or on behalf of Borden Ladner Gervais LLP to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:
   (a) to provide opinion evidence that is fair, objective and non-partisan;
   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and
   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date: December 18, 2024

Michael Killeavy
__________________________________
*Signature*

**TAB 3**

# 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<br>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<br>i) The IESO has been seeking feedback from market participants on MRP market rule batches since 2021;<br>ii) The amendments within the Final Alignment Batch are generally in line with the approved MRP detailed design document;<br>iii) To help address market participant concerns related to market power mitigation, the IESO committed in their August 15th presentation and subsequent discussions to:<br>a. enhance end-to-end user testing;<br>b. effectively delay the designation of constrained areas to a minimum of six months after MRP Go Live;<br>c. provide preliminary data on potential constrained areas and narrow constrained areas based on the first ninety days after MRP Go Live;<br>d. use extra discretion when assessing ex-post mitigation for physical withholding to avoid unintended consequences under specific circumstances; and<br>e. establish the Market Power Mitigation Working Group prior to MRP Go Live;<br>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<br>v) The IESO has committed to continue to work with:<br>a. the Technical Panel to establish the terms of reference of the Market Power Mitigation Working Group;<br>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;<br>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<br>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.<br>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<br>(Renewable Generators) | For<br>1. conclusion of establishing Reference Levels with Market Participants for inclusion within IESO's application of Market Power Mitigation (MPM);<br>2. determination of Terms of Reference for the MPM Working Group, including knowledgeable sectoral membership within the Working Group;<br>3. outcomes regarding addressing concerns and solutions relating to hydroelectric generators, as documented between the Ontario Waterpower Association (OWA) and IESO; and<br>4. conclusion of amendments to contracts held between Suppliers (e.g., wholesale market participant generators) and IESO, contractually triggered by MRP |

| | |
|---|---|
| | 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<br><br>(Generator) | For<br><br>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.<br><br>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.<br><br>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<br><br>(Transmitters) | For<br><br>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<br><br>(Retailers or Wholesalers) | For<br><br>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:<br>- BCACondThresh $25<br>- IBPThresh $100<br>- ORGCondThresh $15<br>- CTEnThresh2BCA $100<br>- CTEnThresh2GM $100<br>- CTORThresh2ORL $25<br>- CTEnThresh2ORL $25<br>- CTORThresh2ORG $25<br>- CTEnThresh2ORG $25<br>- CTEnMinOffer $25<br>- CTORMinOffer $5<br>- ITThresh2NCA $25<br>- ITThresh2DCA $25<br>- ITThresh2BCA $50<br>- ITThresh2GMP $50<br>- ITThresh2ORG $25<br>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<br><br>(Energy Storage) | For<br><br>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.<br><br>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.<br><br>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<br><br>(Consumer) | For<br><br>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<br><br>(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.<br><br>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<br><br>(IESO) | For |

# TAB 4

Ontario Energy Board Commission de l’énergie de l’Ontario

Ontario

# Monitoring Report on the IESO-Administered Electricity Markets

for the period from
May 2015 – October 2015

**November 2016**

PUBLIC

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# Table of Contents

methodology is expected to reduce the cost of the program by approximately $10 million annually.

### *3.2.10 Off-Setting Revenues – Incentives of the IESO's Current Methodology*

The RT-GCG program provides an incentive, in the form of a cost guarantee, for generators to start in real time, whereby if the generator does not receive sufficient revenue to cover its costs of start-up and minimum operation, the IESO makes a payment for the difference. While conceptually straightforward, the specific Market Rules are far more nuanced. RT-GCG payments are made if revenues earned over the guarantee run for output up to MLP are less than the costs for the same period, including an after-the-fact submission of the generator's start-up costs, which may include fuel and O&M costs. To become eligible for the guarantee the generator must be economic in pre-dispatch for half of its MGBRT. This design is flawed, and exposes Ontario consumers to unnecessary guarantee costs.

One flaw is that the revenue calculation used to offset costs provides generators with an incentive to choose to offer their MGBRT hours in a way that both minimizes their offsetting revenues (thereby increasing their guarantee payment) and increases their opportunity to earn profit above MLP and post MGBRT (profits which are not used to offset the guarantee payment). This incentive increases the likelihood that generators operate profitably on an all in basis and still receive a guarantee payment on a given day. A more comprehensive revenue offset envelope would resolve this situation.

Increasing the revenue offset envelope for the RT-GCG will also help alleviate an undesirable and inefficient situation/opportunity that results from the current RT-GCG program.

This situation is best illustrated with an example. Consider a generator that is economically scheduled in HE 7, 8, 9 (half of its six hour MGBRT). The generator is now afforded the opportunity to select its RT-GCG hours to include either HE 7, 8, 9, 10, 11, 12 or HE 4, 5, 6, 7, 8, 9 (or some other six continuous hour period therein). In general, HOEP is lower for hours early in the morning than it is at mid-day.[145] The implication is that generators have an incentive

[145] In 2015, the average HOEP for HE 4-6 was $10.62/MWh and for HE 10-12 was $26.30/MWh, a difference of $15.67/MWh.

to set their MGBRT period to encompass the lowest priced hours (HE 4, 5, 6, 7, 8, 9). By doing so, generators are able to 'use up' their minimum generation period on very low priced hours (even if market prices are $0/MWh the IESO will guarantee cost recovery) and, thanks to the current revenue offset, retain the upside potential of earning profits (above MLP and post-MGBRT) during hours when prices are, in general, higher.

The early morning hours in which generators are selecting to generate are also the same hours in which RT-GCG eligible generators are least needed and risk exacerbating surplus baseload generation (SBG) conditions.

The example described above occurred on August 10, 2015. Generator A (Gen A) selected to begin ramping at 1:00 a.m. for a guarantee run that started at 3:00 a.m. and ended at 9:00 a.m. Gen A earned a guarantee payment for this run of $65,255. However, the facility went on to generate continuously until 11:00 p.m.; no portion of the approximately $153,000 that Gen A earned after 9:00 a.m. was used to offset its RT-GCG payment. A more detailed description of the day's events can be found in Appendix A.

Operationally, the choice by Gen A to begin ramping at 1:00 AM has the effect of exacerbating SBG conditions which Ontario regularly experiences overnight. Often, the IESO control-room utilizes nuclear 'maneuvers', which involve dispatching blocks of nuclear capacity, to address the potential reliability concerns associated with over-generation. In general, the IESO is able to dispatch down nuclear generation whenever it is economic to do so, typically when Ontario prices are negative. On this day, nuclear maneuvers were used at 1:15 AM, 15 minutes after Gen A began ramping its units online. While the Panel cannot definitively state that Gen A's choice to begin ramping at 1:00 AM caused the nuclear maneuver, the Panel can say with confidence that Gen A's decision exacerbated SBG conditions in Ontario and made nuclear maneuvers more likely.

In 2015 there were 25 days when a RT-GCG eligible generation unit was online in the early morning hours at the same time a nuclear unit was dispatched down to help alleviate SBG conditions. The generation units were not online in those hours solely because they were economically scheduled, they were online because of how they chose to structure their offers. In such instances it seems that the RT-GCG program is undermining reliability as much as it is supporting it.

Incenting a generator to begin its MGBRT period in the early morning hours exacerbates the inefficiencies inherent in the RT-GCG program. Since a generation unit needs only half of its MGBRT to be scheduled, it does not matter to the participant how inefficient the 'other' half happens to be, however, it can significantly affect the total cost of its commitment which are borne by Ontario consumers.

Table 3-1 shows the cost of the guarantee payment under two scenarios. The scenario where the generator chose its MGBRT hours and the scenario that is least cost. The generator's choice increased the system cost of the real-time commitment by over $20,000.

***Table 3-1: Profit (Loss) During MGBRT Hours***
***August 10, 2015***
***($)***

| Hour Ending | Generator Choice (MGBRT HE 4-9) | Least Cost (MGBRT HE 7-12) |
|---|---|---|
| **4** | (11,160) | - |
| **5** | (11,160) | - |
| **6** | (5,065) | - |
| **7** | 88 | 88 |
| **8** | 115 | 115 |
| **9** | 119 | 119 |
| **10** | - | (3765) |
| **11** | - | 178 |
| **12** | - | (3,392) |
| **Total** | **(27,305)** | **(6,656)** |

Where an operating loss is a pass through to Ontario consumers, there is no incentive for generators to choose the least cost alternative. Indeed, the current design incents them to do just the opposite.

This incentive can be reversed by adopting the Panel's proposed comprehensive offset methodology. This is illustrated in the example[146] below.

Table 3-2 presents the two different choice options described above (Generator Choice and Least Cost) under two different guarantee calculations (the current and MSP comprehensive). What the table shows is that presently generators are better off choosing to start at 3:00 a.m. ($9,750 profit versus $8,250) under the current calculation, but that preference switches to 6:00 a.m. under the comprehensive calculation ($1,250 profit versus $0). Today, generators are privately better off beginning their GCG commitment as early as possible; however, that private profitability comes at the expense of social efficiency.

***Table 3-2: Comparison of Revenue Offset Methodology ($)***

| Methodology | Option | MGBRT Start Time | Total Revenues^ ($) | Total Costs* ($) | GCG Payment ($) | Net Revenue ($) |
|---|---|---|---|---|---|---|
| Current IESO GCG Offset | 1. Current Participant Choice | 3:00AM | 70,750 | 61,000 | 13,000 | 9,750 |
| | 2. Least Cost Choice | 6:00AM | 63,250 | 55,000 | 7,000 | 8,250 |
| MSP Comprehensive GCG Offset | 3. Current Participant Choice | 3:00AM | 61,000 | 61,000 | 3,250 | 0 |
| | 4. New Participant Choice = Least Cost Choice | 6:00AM | 56,250 | 55,000 | 0 | 1,250 |

^Includes GCG payments
*Includes start-up costs

By considering all revenues earned during the unit's operation, the IESO can reduce the system costs related to many RT-GCG commitments, decrease the overall cost to ratepayers and significantly reduce the risk of exacerbating SBG conditions while still preserving the guarantee that participants will recoup their eligible start-up and minimum costs. Importantly, this scenario allows the generator to operate profitably, which will remain the ultimate pursuit of generators.

[146] The example assumes the following: HOEP from HE 1- 6 = $5/MWh and from HE 7- 21 = $25; marginal costs of generation = $20/MWh; MLP = 100 MW; MGBRT = 6 hrs; MGBRT production is 100 MW for HE 4,5,6 and 150 MW for HE 7, 8, 9; output post-MGBRT is 150 MW from HE 10-21; start-up costs = $10,000; no operating reserve revenues or CMSC payments are earned or received.

The ability to begin MLP operation during inefficient, low-priced hours would not be eliminated entirely as generators will still, in some situations, be able to strategically offer their MGBRT hours, however, the benefit for doing so will be significantly reduced. Of course, the cost guarantee available to generators; the as-offered MGBRT costs and whatever start-up costs are available to them, would be unaffected by such a change.

### *3.2.11 OR Revenue*

The Panel has also reviewed the RT-GCG program from the perspective of offset revenues. As noted above and in previous monitoring reports, the Panel has recommended that additional energy market revenues be used to offset generator costs. In this section, the Panel goes further to recommend that OR net revenues also be used to offset costs. The Panel's view can summarized as, any net revenues generated based on a guaranteed run that was backed by Ontario consumers should go to offsetting costs and any guarantee payment before they go to the generator. Generators remain incented to generate profits, the Panel's recommendations simply raise the threshold where profits begin and guarantee payments end to a level that is fair to Ontario consumers who assume any downside risk that generators run at a loss.

OR revenues were used to offset guarantee costs when the program operated between 2003 and 2009. It was removed from the offset calculation in an attempt to encourage gas-fired generation facilities to offer more OR to the market.[147]

Ostensibly, the concern with including offsetting RT-GCG guarantees with OR net revenue is that generators may reduce the frequency and/or quantity of their OR offers if those net revenues counted against their RT-GCG payment.

In a competitive market generators are motivated to earn as much revenue above their guaranteed costs as possible, since this profit is theirs to keep. In general, generators who earn as much revenue as possible from all sources while online regardless of the guarantee they have started under (day-ahead or real-time) have a better chance of earning revenues in excess of their

[147] For more information on the decision to remove OR revenue from the RT-GCG offset calculation, see the IESO's Market Rule Amendment Proposal, page 12, available at: http://www.ieso.ca/Documents/icms/tp/2009/06/IESOTP_226_3b_MR_00356_R00_R02_Amendment_Proposal_v1_0.pdf

guaranteed costs. A generator whose unused capacity sits idle and is paid to provide operating reserve is better off than the same generator who sits idle and is not paid to do so.

The incentive to offer OR is in the OR price, not in a subsidy from consumers to generators via the guarantee payment. The incentive for generators to offer OR exists absent the IESO's guarantee program. If OR prices are under signalling the need for OR, then the appropriate course of action, as the Panel recommends in Chapter 2 of this report, is to review the pricing methodology in the OR market, not to subsidize generators via the guarantee program.

Furthermore, the Panel makes the observation that net OR revenues are an offset for Day-Ahead Production Cost Guarantee payments. If OR as an offsetting revenue was discouraging OR offers, we would expect to see this in generator day-ahead offers. The Panel has analyzed units who, on a given day, had a DA-PCG schedule and were also scheduled for OR day-ahead and found on average in 2015, 86% of the OR MW's scheduled day-ahead were also scheduled in real-time. This is important in the context of adding OR net revenue when offsetting RT-GCG payments, as currently, DA-PCG payments are also offset by OR net revenues. The fact that OR MW's scheduled for generators in the day-ahead are also scheduled in real-time, shows that offsetting guarantee payments with OR net revenues does not significantly affect generators' OR offer decisions in real-time. Using net OR revenues to offset the guaranteed costs of the RT-GCG is expected to reduce the cost of the program by more than $2 million annually.

The Panel recommends that the revenues used to offset the guaranteed costs be expanded to include all net energy and OR revenues as well as all CMSC revenues received from the start of a RT-GCG commitment until the unit either begins a Day-Ahead commitment or de-synchs from the grid. The Panel has calculated that implementing such a change will reduce the cost of the program by nearly $10MM annually while incenting efficient offers from generators and reducing the incentive for generators to inefficiently schedule their guarantee hours.

***Recommendation 3-2***

***The Panel recommends that the IESO modify the Real-time Generation Cost Guarantee program such that the revenues that are used to offset guaranteed costs under the program are expanded to include any net energy and operating reserve revenues earned, as well as all congestion management settlement credit payments received, on:***

> ***(a) output above a generation facility's minimum loading point during its minimum generation block run time (MGBRT), and***
>
> ***(b) output generated after the end of the facility's MGBRT.***

### *3.2.12 Materiality of Implementing the Panel's Recommended Changes*

The Panel has calculated that by adopting the Panel's proposed comprehensive offset methodology, including net OR revenue in the offset calculation and removing the guarantee of start-up O&M, the IESO would reduce the annual costs related to the RT-GCG program by approximately $40 million per year. Table 3.2 shows the average annual effect each recommended change would have had since 2010. In total, the Panel's recommended changes would have reduced the cost of the RT-GCG program by just under $300 million over the past six years.

***Table 3-3: Annual RT-GCG Savings***
***2010-2015***
***($ millions)***

| Year | Actual RT-GCG Payments | Savings from Including OR | Savings from Comprehensive Offset Methodology | Savings from Removing O&M from the Guarantee | Total Savings[148] |
|---|---|---|---|---|---|
| **2010** | 72.8 | 0.5 | 18.8 | 55.5 | 60.2 |
| **2011** | 71.7 | 1.2 | 12.9 | 55.6 | 59.6 |
| **2012** | 78.4 | 0.8 | 18.3 | 61.1 | 66.1 |
| **2013** | 63.5 | 2.4 | 11.1 | 38.3 | 43.2 |
| **2014** | 61.5 | 1.9 | 4.5 | 27.9 | 30.6 |
| **2015** | 57.1 | 2.1 | 7.3 | 35.1 | 39.0 |
| **Total** | **405.0** | **8.8** | **72.8** | **273.5** | **298.6** |

### *3.2.13 Concluding Observations*

On September 13, 2016, a majority of the IESO's Technical Panel members voted against (six Panel members voted against and four Panel members in favour of) recommending the IESO's proposed RT-GCG market rule amendments to the IESO Board for approval. A key concern among those voting against recommending the market rule amendments was the limited level of detail in the market rule amendments relative to detail expected to be included in a market manual. On October 13, 2016, a stakeholder meeting was held to discuss the IESO's proposed approach for allocating planned maintenance costs to the RT-GCG program for the purpose of determining pre-approved, resource-specific costs under the framework and to discuss and seek feedback on a draft market manual.

The history of the RT-GCG program and its evolution, in particular in more recent years, highlights an area of concern regarding the IESO's stakeholder engagement processes. Those processes appear on paper to be quite robust and make provision for participation by stakeholders representing a broad spectrum of interests. However, in the Panel's experience the IESO's stakeholdering processes tend to be dominated by those with a direct and substantial financial interest in the outcome. The relative absence of other stakeholders has been

[148] Since RT-GCG payments cannot be negative values, the Total Savings reported in Table 3-2 are less than the sum of savings from OR, comprehensive offset methodology and the removal of O&M. The savings from incorporating all changes at once is bounded at a $0 RT-GCG payment.

acknowledged by the IESO through its articulation of the need to encourage “effective representation of the public in each engagement, especially those groups that have a tendency to remain silent or are reluctant to engage”.[149] The Panel has voiced its support for this principle in the context of the Market Renewal initiative.[150]

The Panel also notes that through the flexibility stakeholder engagement described in Chapter 4, the IESO has identified a number of criteria by which it intends to assess potential options to meet its flexibility needs: technology neutrality, competitiveness, transparency, enduring solution and cost effectiveness.  The Panel believes these are useful criteria and that they could equally be applied to assess and improve the RT-GCG program. Table 3.4 below offers a preliminary assessment of the RT-GCG program using these criteria.

[149] For more information see the IESO’s Engagement Principles document, available at: http://www.ieso.ca/Documents/consult/IESO-Engagement-Principles.pdf
[150] For more information see the Panel’s submission to the Market Renewal stakeholder engagement, available at: http://www.ieso.ca/Documents/consult/ME/ME-20160506-Market-Surveillance-Panel.pdf

*Table 3.4: Assessing the RT-GCG Program*

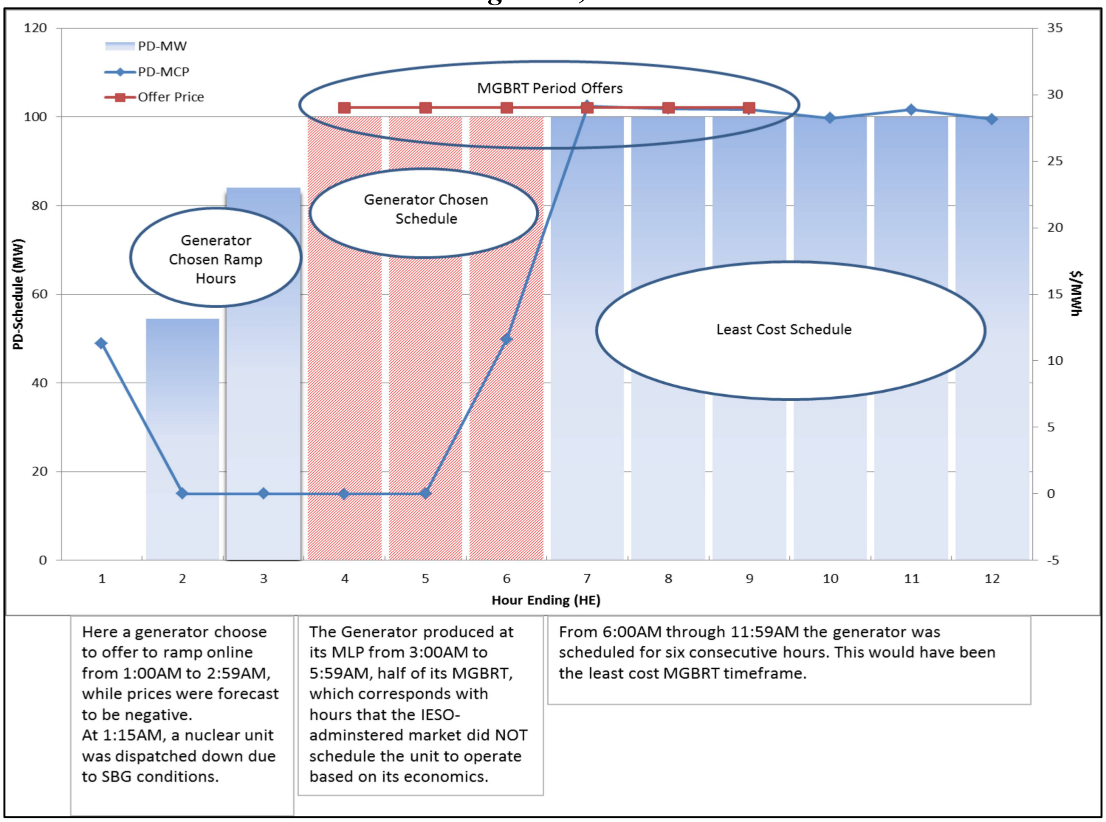
| Criteria | Assessment | Implications |
|---|---|---|
| **Cost Effectiveness** | Costs have increased over 400% per start since the guarantee of start-up O&M despite decreasing fuel prices. MSP analysis shows minimal need for program to meet domestic reliability needs | Costs are in excess of requirements to meet domestic reliability, yet the IESO has decided to defer cost reductions for several years |
| **Competitiveness** | Start-up O&M costs are recovered via after-the-fact cost submissions and are not subject to competitive discipline | Dispatch order distorted<br>No competitive incentive to manage costs |
| **Transparency** | 97.5% of start-up O&M costs to be determined through closed door bi-lateral discussions | Lack of transparency impedes assessment and improvement |
| **Enduring** | RT-GCG widely recognized as sub-optimum solution in need of replacement as part of broader market reform, but entrenched for at least next three years | Current design ensures ongoing inefficiency and unnecessary costs. Panel recommendations offer short-term mitigation. |
| **Technology Neutrality** | Extending the guarantee of start-up O&M further entrenches the subsidy paid to non-quick start fossil-fuelled generation | Absence of technology neutrality discourages the development and provision of other potential solutions[151] |

[151] Other sources of reliability resources include imports, storable hydro, dispatchable wind and solar, dispatchable load, storage, etc.

## *3.3 Appendix A*

Figure 3.A1 below depicts an example of this situation from August 10, 2015.

***Figure 3-A1 : Example of 'Choosing' MGBRT Period***
***August 10, 2015***




In this example, the Gen A's MGBRT offers were economic for HE 7, 8, 9, and uneconomic for HE 4, 5, 6. The generator began ramping online at 1:00 AM in order to be at its MLP by 3:00 AM, thus beginning its six hour MGBRT period. By starting its MGBRT period at 3:00 AM, the generator was able to 'use up' its guarantee hours from 1:00 AM to 8:59 AM, and then operate as a merchant facility from 9:00 AM until it desynchronized from the grid at nearly 11:00 PM. Revenues earned over these 14 hours, approximately $153,000 on this day, are not currently factored into the generator's cost guarantee.

**TAB 5**

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**File No. 025001.000106**

November 7, 2024

**BY EMAIL & RESS**

Ms. Nancy Marconi, Registrar
Ontario Energy Board
PO Box 2319
26th Floor, 2300 Yonge Street
Toronto, ON M4P 1E4

Dear Ms. Marconi:

**Re: Capital Power Corporation, Thorold CoGen L.P., Portlands Energy Centre L.P. dba Atura Power, St. Clair Power L.P., TransAlta (SC) L.P. (the "NQS Generation Group")**
**Application for Review of Amendments to the Independent Electricity System Operator ("IESO") Market Rules**

As legal counsel to the NQS Generation Group, we are filing with this letter an Application for Review of Amendments to the IESO's Ontario Electricity Market Rules under s. 33(4) of the *Electricity Act, 1998* ("**Application**") and in accordance with section 16 of the Ontario Energy Board's ("**OEB**") *Rules of Practice and Procedure* issued on March 6, 2024.

If you have any questions or concerns, please do not hesitate to contact me.

Your truly,

**BORDEN LADNER GERVAIS LLP**

Colm Boyle

**ONTARIO ENERGY BOARD**

**IN THE MATTER OF** the *Electricity Act, 1998*, s.33;

**AND IN THE MATTER OF** the *Ontario Energy Board Act, 1998*, s.21;

**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 a review of the Market Renewal Program Market Rule Amendments passed by the Board of Directors of the Independent Electricity System Operator ("IESO") on October 18, 2024.

# APPLICATION FOR REVIEW OF AMENDMENTS TO THE INDEPENDENT ELECTRICITY SYSTEM OPERATOR MARKET RULES

**November 7, 2024**

Counsel for the NQS Generation Group
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## 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

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[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.

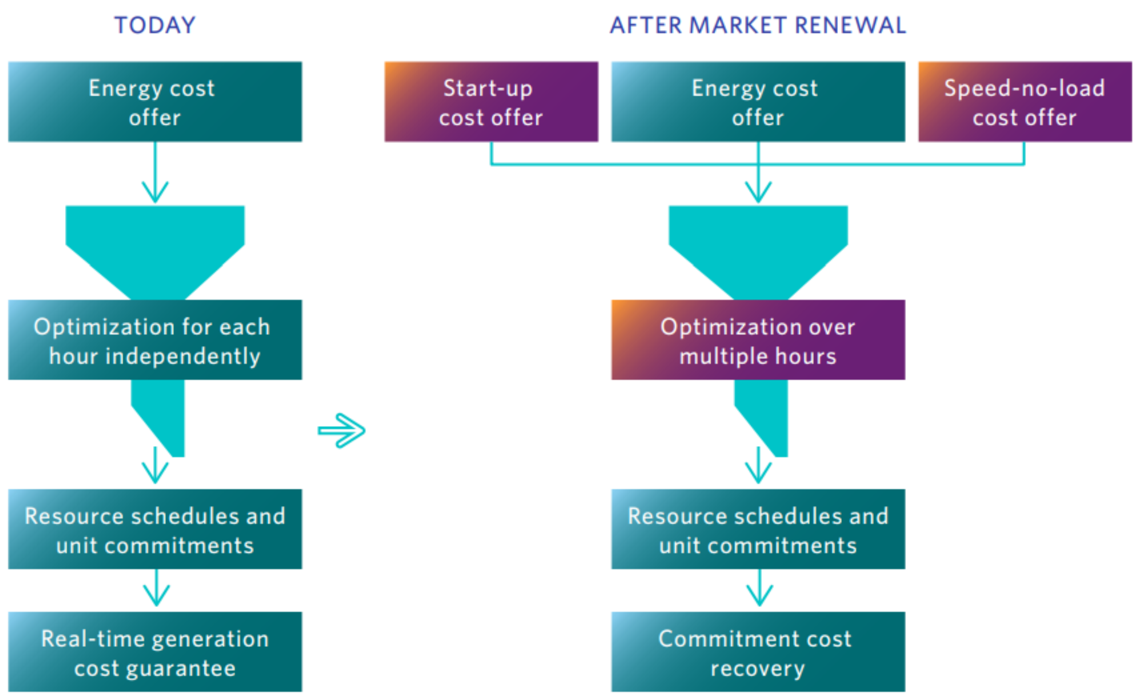
e. The current pricing algorithm uses a 3x ramp rate and an unconstrained dispatch algorithm to dampen price volatility and ultimately lower Hourly Ontario Energy Price ("**HOEP**") levels. Under MRP, a 1x ramp rate and a constrained dispatch algorithm will be used which will add volatility to LMPs relative 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 first 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.

## Schedule A

**Additional materials requested to be produced by the IESO in relation to the pending appeal of the Market Renewal Program ("MRP") amendments under section 21 of the *Ontario Energy Board Act, 1998*.**

1. Information relating to the impact of MRP on the NQS Generation Group, including all materials, analysis, correspondence, and records related to:

    a. how the IESO's stated intention of not extracting financial value from contracts with the NQS Generation Group was considered, planned, and executed under MRP;

    b. how the IESO's stated intention of maintaining the allocation of risk and reward that has been established by contracts with the NQS Generation Group to the greatest extent possible under MRP was considered, planned, and executed;

    c. how the IESO compensates market participants under MRP for facility startup costs previously recovered in the RT-GCG program;

    d. how the IESO envisioned, planned, and executed the integration of the deemed dispatch model into MRP, including the economics, risk, and scheduling aspects of the deemed dispatch model with existing contracts;

    e. how the IESO considered, planned, and executed on the lack of transparency in market pricing and scheduling signals under MRP, since a lower incremental energy offer will not necessarily guarantee dispatch;

    f. how the IESO intends to address the lack of transparency in (e);

    g. Annual savings from changes to in the design and settlement of commitment programs for NQS generators;

    h. The dispatch and commitment of NQS generators in the energy market under the current Market Rules compared to the MRP Amendments;

    i. The impact of financial settlement using Make Whole Payments (MWPs) compared to Congestion Management Settlement Credits (CMSCs) for NQS generators;

    j. Review of the design of the current deemed dispatch contracts with NQS generators compared to contracts with similar NQS assets in other competitive wholesale markets;

    k. The number of instances when assets – NQS and other non-NQS assets – will be dispatched out of economic merit based on incremental energy offers;

    l. Pricing analysis in the various energy zones under the current Market Rules compared to the MRP Amendments;

m. Impact on historical imputed production by moving to a single trigger startup (i.e. if generators were re-settled in the past using a single trigger, how would have imputed production changed).

n. The potential decrease to system cost by allowing multiple offer windows in the day ahead (MRP is currently one and done, with little transparency).

2. Information relating to the consistency of the MRP Amendments with the purposes of the *Electricity Act*, including all materials, analysis, correspondence, and records related to:

   a. how the MRP Amendments impact the scheduling and dispatch of market participants;
   b. Updates to the original benefits case for MRP and the current savings that are expected from the MRP Amendments;
   c. Updates to market design changes included in the MRP Amendments in response to commitment and dispatch concerns raised by Market Participants throughout the MRP stakeholder engagement process;
   d. Design or changes to the contracts included in the Long-Term and Medium-Term procurements in response to the MRP Amendments; and
   e. The financial impact (negative or positive) on changes to NQS and non-NQS Market Participants as a result of the MRP Amendments.