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

NOTICE OF MOTION

The Independent Electricity System Operator (the "**IESO**") will make a motion to the Ontario Energy Board (the "**Board**" or "**OEB**") at its offices at 2300, Yonge Street Toronto on a date and time to be fixed by the Board.

PROPOSED METHOD OF HEARING: The IESO proposes that the motion be heard in writing so that it may be disposed of in accordance with the schedule for this proceeding established by the Board's Decision and Procedural Order No. 2 dated December 2, 2024 ("**Procedural Order 2**").

THE MOTION IS FOR AN ORDER:

(a) striking as irrelevant, out-of-scope, and contrary to Procedural Order 2 the portions of the Applicants' "Expert Evidence in Appeal" dated December 18, 2024 (the "**Expert Report**") that purport to deal with the alleged impacts of the MRP Amendments on the Applicants' contractual rights and obligations listed in paragraph 16 and highlighted in Appendix "A" to this Notice of Motion;

(b) directing the Applicants to deliver and file an amended Expert Report on or before January 3, 2025 that redacts the portions of the Expert Report struck out in accordance with paragraph 1;

(c) requiring the Applicants to pay the IESO's costs for this motion to be assessed at the conclusion of the proceeding; and

(d) such further and other relief as the OEB may deem just.

THE GROUNDS FOR THE MOTION ARE:

1. On November 7, 2024, the Applicants commenced an application under section 33 of the *Electricity Act, 1998,* SO 1998 c. 15 (Schedule B) (the "***Electricity Act***"), requesting that the OEB review amendments to the market rules (the "**MRP Amendments**") made by the Independent Electricity System Operator (the "**IESO**"), revoke the MRP Amendments, and refer them back to the IESO for further consideration.

2. As required by section 33(6) of the *Electricity Act,* the OEB must issue an order with its final decision within 120 days of its receipt of the Application, being March 6, 2025.

3. On November 19, 2024, the OEB issued Procedural Order No. 1 which set a date for a pre-hearing conference to address intervention and cost eligibility requests, cost responsibility, the issues list and scope of the proceeding, evidentiary matters and the proceeding schedule.[1]

4. Through written and oral submissions before and at the pre-hearing conference, the Applicants and the IESO made substantive submissions on the scope of the proceeding.

5. The Applicants took the position that the MRP Amendments result in unjust discrimination to non-quick start gas-fired generators, which discrimination is made worse by their procurement contracts with the IESO. The Applicants argued, among other things, that the interaction of these contracts with the market rules fell within the scope of the issues to be determined and that the OEB should not assess the MRP Amendments in a hypothetical vacuum but rather must consider the contractual implications for the MRP Amendments.[2]

6. The IESO, on the other hand, took the position that while allegations that MRP Amendments alone are unjustly discriminatory are properly before the OEB, the Applicants' contract allegations, including their position that the unjust discrimination is made worse by the contracts or that the IESO's proposed Term Sheet amendments are not sufficient to mitigate the financial impact of the MRP Amendments, exceed the bounds of a market rule amendment review under section 33(9) of the *Electricity Act* and are out-of-scope. In particular, section 33(9) limits the grounds for review to a determination of whether the market rule amendments are: (i)

[1] Procedural Order No. 1 dated November 19, 2024 at pp. 2-4.

[2] Applicant's Pre-hearing Conference Submission dated November 25, 2024 at para. 5; Letter from C. Boyle to Registrar dated November 14, 2024 at p. 2; Transcript from OEB Pre-Hearing Conference ("Pre-Hearing Transcript") at p. 67, lines 1-10, p. 74, lines 18-21.

inconsistent with the purposes of the *Electricity Act*, or (ii) unjustly discriminate against a market participant or class of market participants and does not include the impact of market rule amendments on the commercial interests of out-of-market contract counterparties.[3]

7. In addition, if the MRP Amendments are upheld by the OEB, the Applicants' contracts specifically include provisions which provide that, in the event of market rule amendments, the parties will make specific amendments to the contracts to address the market design changes and to mitigate any adverse impacts resulting from these changes. If the parties are unable to agree on contractual amendments, the parties have recourse to arbitration.[4]

8. Following the pre-hearing conference, the OEB issued Procedural Order 2 which, among other things, confirmed the issues for the hearing and addressed the scope of the proceeding.

9. With respect to the issues list, the OEB ordered that the only issues to be determined on this application, in accordance with subsection 33(9) of the *Electricity Act,* are whether the Amendments: (i) are inconsistent with the purposes of the Act; or (ii) unjustly discriminate against or in favour of a market participant or class of market participants.[5]

10. With respect to the scope of the proceeding, the OEB determined that "the contracts themselves and the provisions for generators to seek amendments to those contracts are separate from the issue of whether the Amendments are inconsistent with the purposes of the Electricity Act or will result in unjust discrimination" and that the Applicants have "**not established any basis on which contractual matters could be within the scope of this section 33 review**."[6] The OEB further held that "[t]he rules themselves must avoid unjust discrimination, and the remedy does not lie in a contractual arrangement with a market participant. The remedy is to revoke the rule and send it back to the IESO for further consideration, regardless of what any particular contract may provide for."[7]

11. The OEB expressed its clear intention that its ruling on scope was to govern subsequent steps in the proceedings when it directed in Procedural Order 2, in reference to the Technical

[3] Letter from P. Duffy to Registrar dated November 11, 2024 at pp. 2, 4; IESO's Written Submissions in Advance of November 26, 2024 Pre-Hearing Conference dated November 22, 2024 at paras. 2, 5, 18; Pre-hearing Transcript at p. 82, lines 6—23, p. 83, lines 1-28, p. 84, lines 1-28, p. 85, lines 1-20.

[4] IESO Pre-Hearing Submissions at paras. 3, 12-13, 17

[5] Decision and Procedural Order No. 2 dated December 2, 2024 ("Procedural Order 2") at p. 2.

[6] Procedural Order 2 at p. 6.

[7] Procedural Order 2 at p. 6.

Conference, that "parties should not engage in detailed exploration of items that do not appear to be material or are inconsistent with the OEB's findings on the scope of the proceeding and evidentiary matters as set out in this Decision."[8]

12. In accordance with Procedural Order 2, on December 11, 2024, the IESO delivered its preliminary evidence describing: (i) the objectives of the MRP Amendments; (ii) a detailed overview of the MRP Amendments; (iii) how the MRP Amendments meet the objectives of the MRP Amendments; and (iv) the key changes to the current market rules and the expected impacts on market participants.

13. On December 18, 2024, the Applicants delivered the Expert Report that does not comply with the direction of the Board in Procedural Order 2. The Expert Report was accompanied by a letter from Mr. Boyle, counsel for the Applicants, that attempts to rationalize the Applicants' disregard of Procedural Order 2.

14. In his letter, Mr. Boyle openly acknowledges that "[t]he OEB ruled in Procedural Order No. 2 that the NQS Generation Group has not established any basis on which contractual matters could be within scope of this section 33 review" but, despite this acknowledgement, goes on to state "the OEB must as a matter of law and procedural fairness consider the financial consequences of the Market Rule Amendments under the existing contracts between the IESO and NQS Generation Group to assess the full factual extent of the unjust economic discrimination caused by Market Rule Amendments. In our view Procedural Order No. 2 does not exclude consideration of the consequential economic impacts of the Market Renewal Amendments on the NQS Generation Group arising from their contracts."[9] Mr. Boyle goes on to repeat the very same arguments that were made by the Applicants and OEB Staff at the pre-hearing conference and were squarely rejected by the OEB in Procedural Order 2.

15. The Expert Report itself is replete with inadmissible evidence in clear breach of Procedural Order 2 concerning the impact of the MRP Amendments on the Applicants' contracts and how such impacts are not adequately mitigated by the IESO's proposed Term Sheet amendments to the contracts.

[8] Procedural Order 2 at p. 13.
[9] Letter from C. Boyle to Registrar dated December 18, 2024 at p. 2.

16. Specifically, the Expert Report includes the following paragraphs and portions of evidence that ought to be struck out or disregarded by the OEB as irrelevant and out-of-scope for this hearing:

(a) Paragraph 8 (in its entirety) – this paragraph provides an overview of Section 7 of the Expert Report which "reviews implications of the MRP Amendments on contracts to which the NQS Generators are counterparty to with the IESO.";

(b) Paragraph 9 (the last sentence) – purports to provide evidence that "the IESO has not taken steps to address the financial harm imposed by the MRP Amendments through effective amendments to NQS Generators' contracts.";

(c) Paragraph 16 (one sentence) – states "[t]hese negative financial impacts will not be offset through commensurate amendments to the contracts that NQS Generators hold with the IESO.";

(d) Paragraph 17 (last sentence) – states "[t]his impact is not accounted for in the "deemed" dispatch settlement structure contained in the contracts the NQS Generators hold with IESO.";

(e) Paragraph 18 (last sentence) – states "[f]om 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.";

(f) Paragraph 21 (in its entirety) – purports to provide evidence on the contract amendment process and the purported failure of that process to sufficiently address the financial impact for the Applicants of the MRP Amendments;

(g) Paragraph 57(g) (last sentence) – states "[a]s 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.";

(h) Paragraphs 66-67 (in their entirety) – purports to provide evidence that the IESO proposed contract amendments for wind and solar generators will eliminate the financial risk of a financially binding DAM;

(i) Section 7: How and Why MRP Implications for NQS Generators Matter for MRP Related Contract Amendments (in its entirety; paragraphs 69-91) – this section purports to give evidence on the implications of the MRP Amendments on the Applicants' contracts and historical context of previous disputes between contracted generators and various IAM market design decisions undertaken by the IESO;

(j) List of References (entries 3 and 4 on page 55) – Market Renewal Program Impact on Clean Energy Supply Contracts: Overview and Update; and Market Renewal Impact on CES Contracts Webinar Materials;

(k) Appendix B: Detailed Daily Settlement Example (the first sentence and sections 3 and 4) – these sections present a theoretical financial analysis that incorporates and is premised upon the terms of an existing contract represented by a "proxy NQS Generator"; and

(l) Appendix C: Historical Annual Financial Impact of MRP amendments (Figure 23 "Contract Financial Impact" and the following paragraph) – this figure and paragraph present the contractual financial impact for a "proxy NQS Generator".

17. The OEB should grant an order striking these offending portions of the Expert Report now. The IESO will be prejudiced if the offending evidence remains in the record and it is required to prepare responding evidence (due on January 6, 2025) and argument to irrelevant and out-of-scope evidence that is in breach of Procedural Order 2.

18. The OEB has jurisdiction to strike inadmissible evidence and doing so is consistent with the OEB's past practice in section 33 reviews and other types of proceedings where the scope of the Board's inquiry is tightly defined by a statutory provision.

19. In EB-2007-0040 (the "**3X Ramp Rate Case**"), the Board ordered that evidence related to the IESO's stakeholdering process, which was determined to be irrelevant to the statutory test in subsection 33(9), "be struck from the record", including the submissions made by the applicants

in that case related to that material.[10] When provided with the opportunity to do so, the Board "decided to issue a decision now on the matter of the relevance of the evidence with respect to the process, rather than deferring it, as [the applicant's counsel] suggested, in order that we can proceed with the case in a more orderly manner."[11] The same rationale should be applied in this situation to strike the offending evidence now.

20. In EB-2011-0013/EB-2011-0014/EB-2011-0015, Union Gas brought applications for the designation of a gas storage pool pursuant to sections 36.1(1) and 38(1) of the *Electricity Act,* leave to construct a transmission pipeline, and licenses to drill injection/withdrawal wells. The OEB's procedural order No. 1 ordered that "the scope of this proceeding will be limited to the Issues List" which included the following issue: "Does the applicant have the necessary leases and agreements with the directly affected landowners." Kent Federation Agriculture ("**KFC**") filed evidence arguing that the compensation under the leases was inadequate and Union filed an application to strike KFC's evidence on the ground that it was not relevant to the issues in the proceeding, which application was granted by the OEB.[12]

21. Similarly, in RP-1999-047 (the "**Century Pools Phase II Proceeding**"), another application by Union for designation, injection, pipeline construction and well drilling, the OEB struck evidence filed by a storage association on the fairness of storage compensation as irrelevant to the issues in the proceeding.[13]

22. The IESO rejects the Applicants' contention that the offending evidence must be admitted as a matter of procedural fairness. Under subsections 15(1) and 25.01 of the *Statutory Powers Procedure Act*, RSO 1990, c S.22, the Board has the authority to control its own process and may admit evidence that is "relevant" to the subject-matter of the proceeding; by implication, it is also entitled to make rulings that certain evidence is irrelevant.[14] Refusing to admit evidence is not an automatic breach of natural justice and only results in a denial of natural justice where the refusal has a significant impact on the fairness of the proceeding.[15] Striking evidence that pertains to an

[10] EB-2007-0040, Decision and Order (Issued April 10, 2007 and as corrected on April 12, 2007) at p. 10.
[11] EB-2007-0040, Decision and Order (Issued April 10, 2007 and as corrected on April 12, 2007), Appendix A at p. 91.
[12] EB-2011-0013/EB-2011-0014/EB-2011-0015, Decision on Motion to Strike Evidence and Procedural Order No. 3 dated May 5, 2011.
[13] RP-1999-047, Decision with Reasons (Issued March 30, 2000), at paras. 1.2.5 – 1.2.8.
[14] *The Corporation of the City of Kawartha Lakes v. Director, Ministry of the Environment*, 2012 ONSC 2708 at para. 56.
[15] *Kraft Canada Inc. v. Menkes Lakeshore Ltd.*, 2007 CanLII 65611 at para. 31 (ON SCDC).

issue which the Board has already ruled is out of scope – a ruling which the Applicants elected not to challenge and seemingly accept in their cover letter – does not amount to a denial of natural justice.

23. Further, for the reasons articulated at the pre-hearing conference, it is important that the parties have clear direction on the scope of this proceeding to ensure that it proceeds efficiently and in accordance with the statutory 120-day timeline. The IESO should not be required to respond to extensive evidence on a matter that the Board has already judged to be outside of the scope of this proceeding. Moreover, allowing the Expert Report to remain in the record in its current form will beget questioning on out-of-scope topics at the Technical Conference in clear contradiction to the expectations of the Board panel expressed in the Procedural Order 2. Parties should utilize motions to strike evidence to clarify the contents of the record, as the Divisional Court has recognized:

> To fail to define the appropriate record for the Court before the hearing encourages the proliferation of collateral issues, as occurred in this application. Filing material by one party inevitably precipitates a response from the opposite party. The consequence of failing to define the record is a proceeding before this court that becomes unnecessarily complicated, expensive and lengthy. For the parties and for the court, the ground is continually shifting, and the core issues may be eclipsed by the procedural issues.[16]

24. The Board should require the Applicants to pay the IESO's costs for this motion to be assessed at the conclusion of the proceeding. This motion would have been entirely unnecessary if the Applicants had complied with the Board's direction in Procedural Order 2. The Board should not countenance such behaviour from sophisticated parties such as the Applicants that are represented by experienced counsel.

25. The following materials will be relied upon in this motion:

(a) Application dated November 7, 2024;

(b) letter from C. Boyle to Registrar dated November 14, 2024;

(c) Applicant's Pre-hearing Conference Submission dated November 25, 2024;

[16] *Sierra Club Canada v. Ontario (Ministry of Natural Resources and Ministry of Transportation)*, 2011 ONSC 4086 at para. 8.

(d) letter from P. Duffy to Registrar dated November 11, 2024;

(e) IESO's Written Submissions in Advance of November 26, 2024 Pre-Hearing Conference dated November 22, 2024;

(f) transcript from OEB Pre-Hearing Conference held on November 26, 2024;

(g) letter from C. Boyle to Registrar dated December 18, 2024;

(h) Applicants' "Expert Evidence in Appeal" dated December 18, 2024; and

(i) any other material that the OEB deems just.

December 23, 2024

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

Glenn Zacher
gzacher@stikeman.com
Tel: 416-869-5688
Patrick Duffy
pduffy@stikeman.com
Tel: 416-869-5257
Lesley Mercer
lmercer@stikeman.com
Tel: 416-869-6859
Fax: 416-947-0866

Lawyers for the IESO

Appendix “A”

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

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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.

[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).

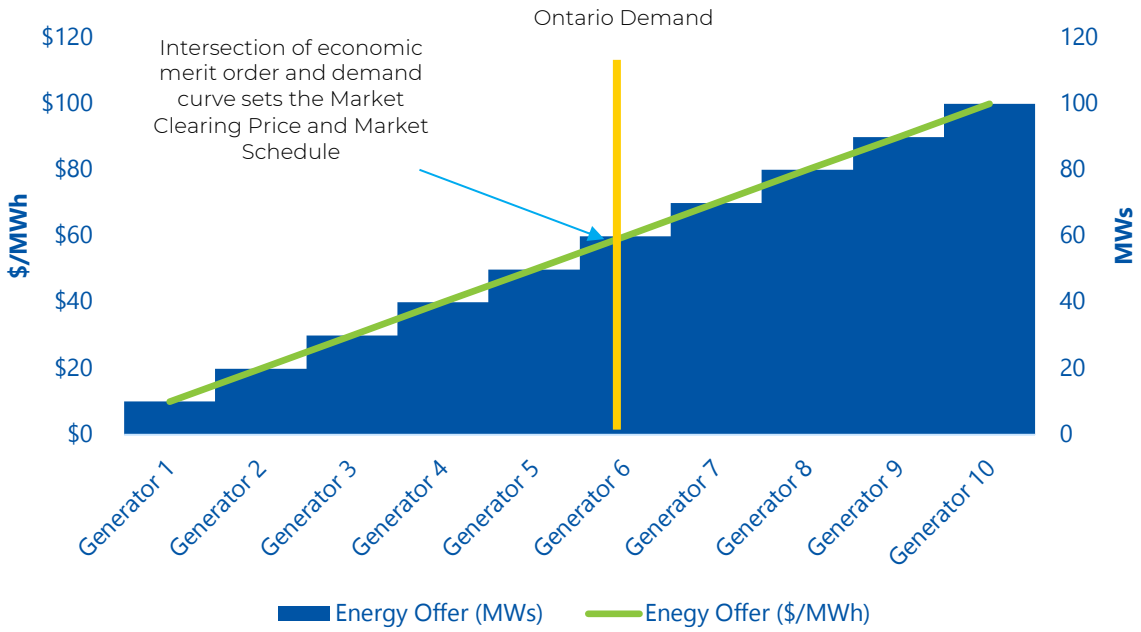
29. The unconstrained mode produces wholesale "market" prices and market schedules by assuming there are no transmission constraints, transmission losses, or other

[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

[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.

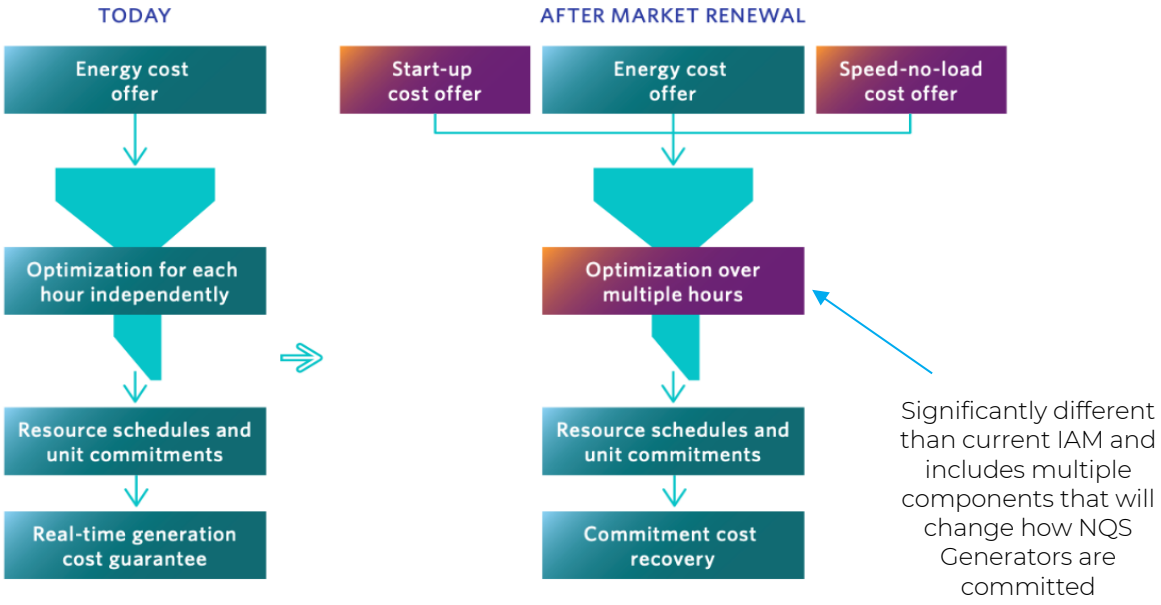
5.4 *How NQS Generators Participate Within the IAM Under Legacy IAM Versus Under MRP IAM*

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.

[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.

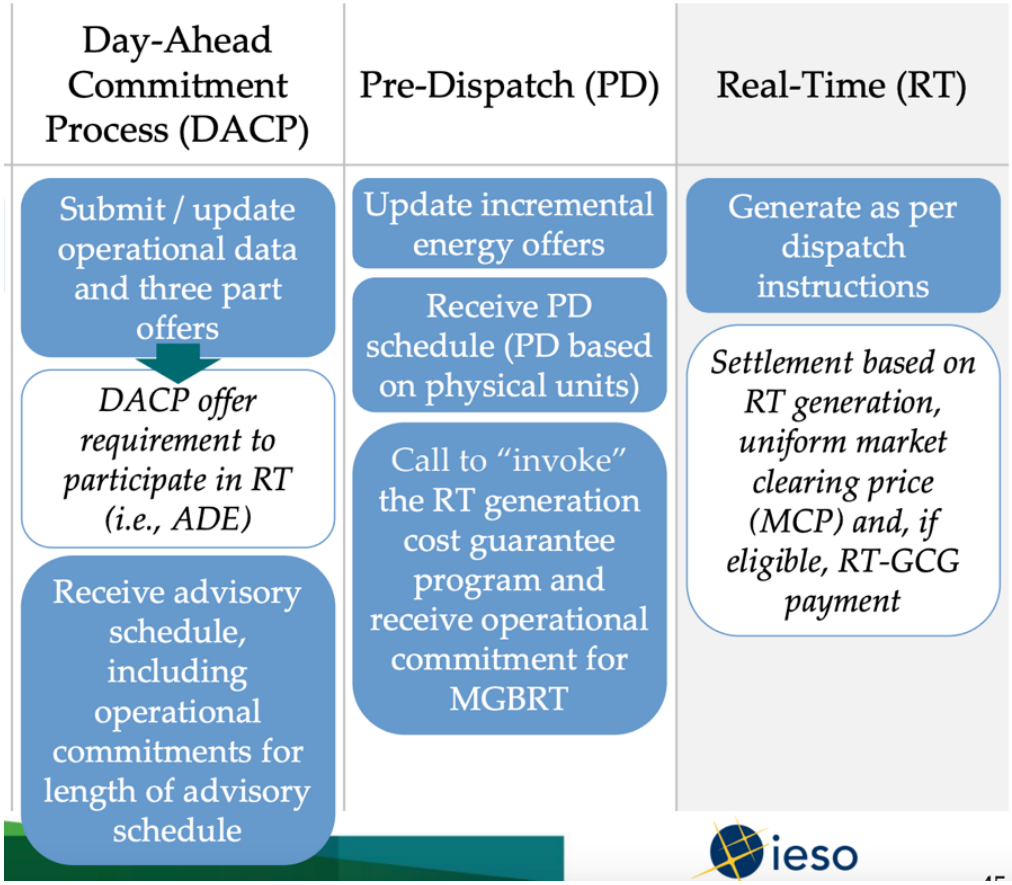
b. For NQS Generators, the RTM energy revenues in the IAM are calculated (for simplicity purposes) by multiplying the amount of supply scheduled in the unconstrained market by the MCPs.

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

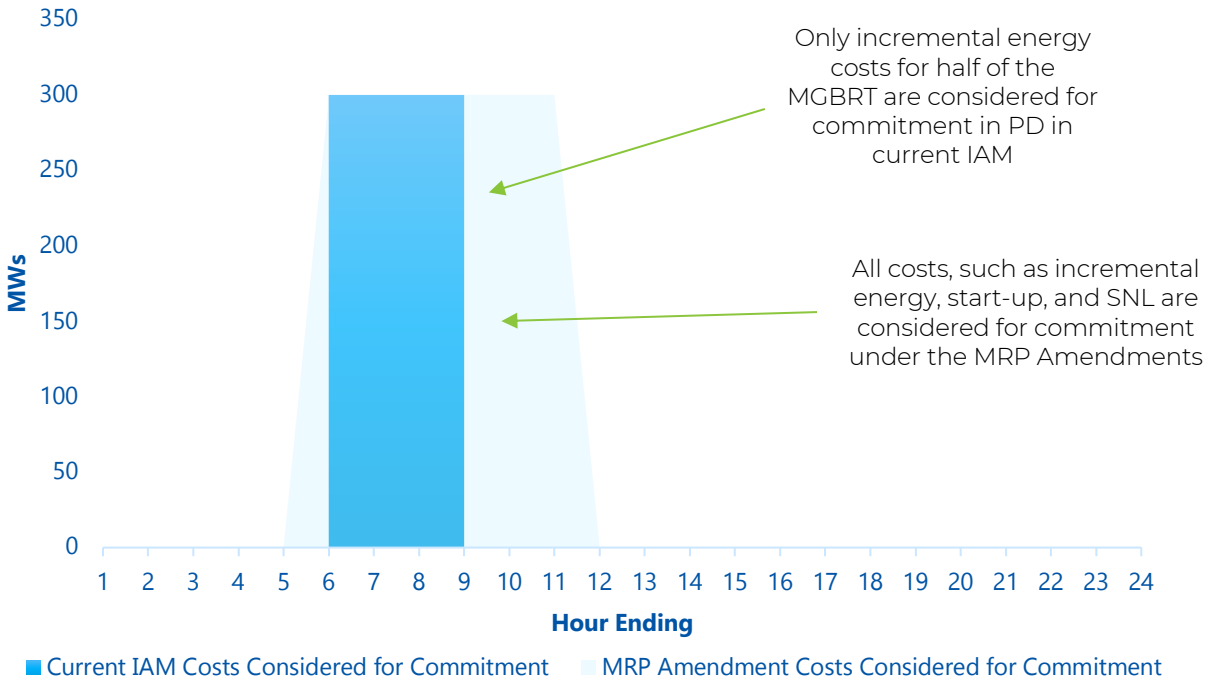


Figure 6 Costs Included in Calculation Engine for Commitment[14]

	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**

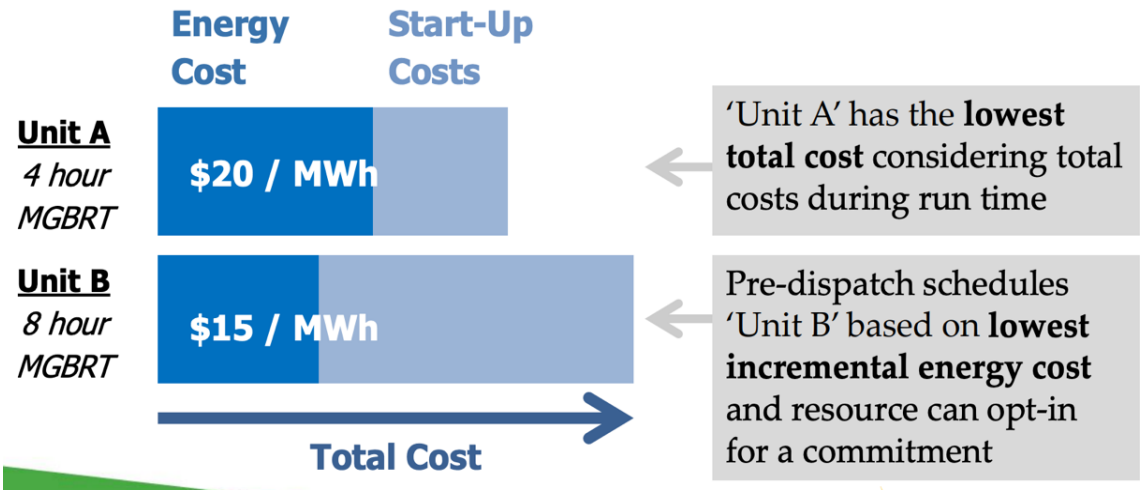
e. This highlights the different financial barriers to commitment for NQS Generators based on the current IAM compared to the MRP Amendments. In the current IAM, only the costs related to an NQS Generator's incremental energy offers for half of its MGBRT are used to invoke a commitment – if those offers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

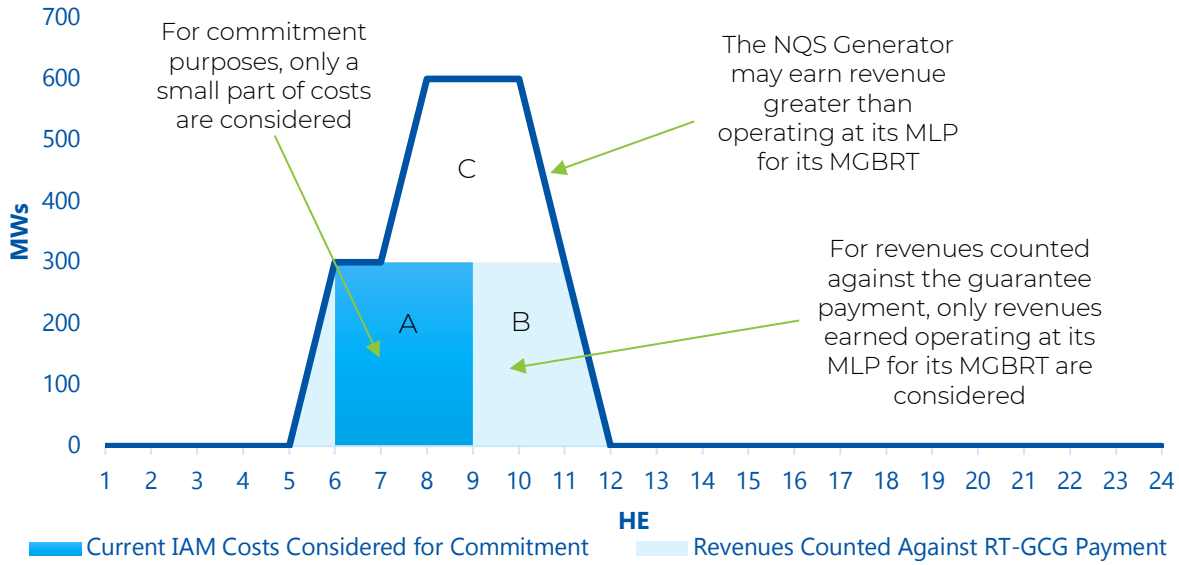
a. The MRP Amendments also include significant changes to the IESO's commitment programs for NQS Generators – particularly the elimination of the RT-GCG program and replacement with RT-GOG program that will produce negative financial outcomes for NQS Generators. At a high-level, the RT-GCG program allows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

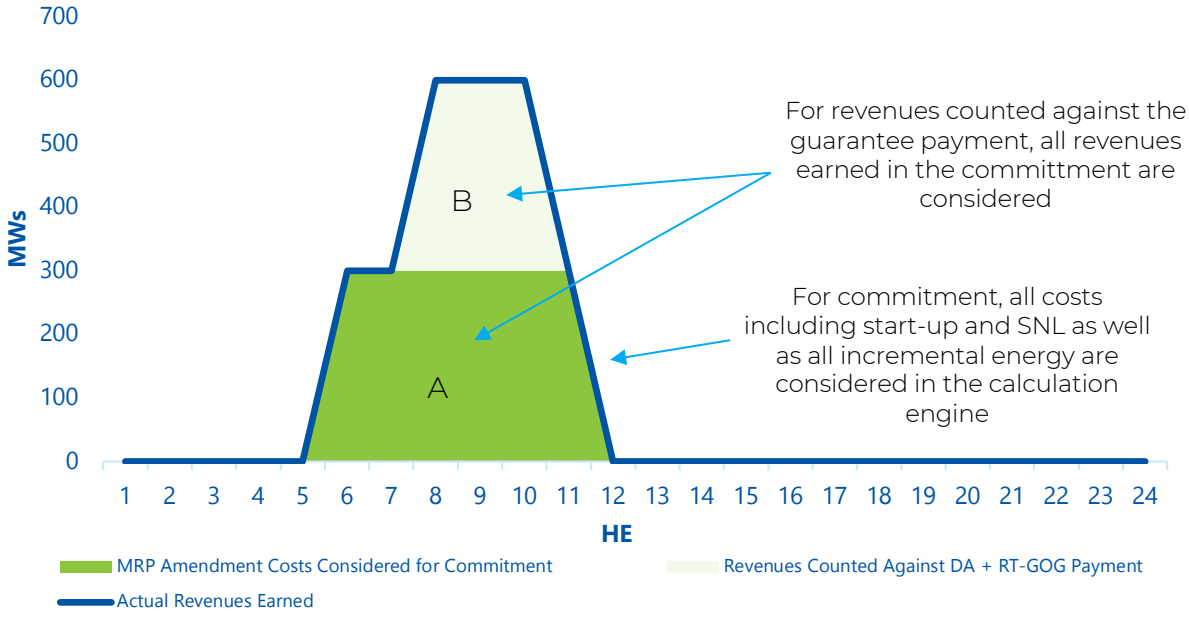


c. In the example above, only the costs in A are considered for commitment (i.e., incremental energy offers for half of its MGBRT). When calculating the RT-GCG payment – which is the difference in all of the costs to bring the generation unit online and revenues earned in the IAM – only the revenues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

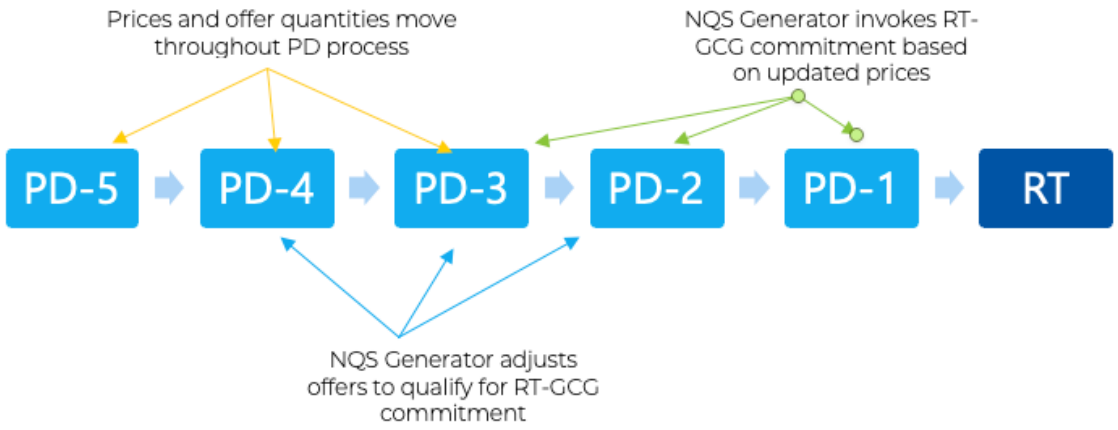


e. Additionally, the RT-GCG program does not include OR revenues earned by NQS Generators to offset guarantee payments. NQS Generators are often committed to provide OR to maintain the reliability of the grid. When NQS Generators are committed through the RT-GCG program, the spare energy available above 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]

[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-

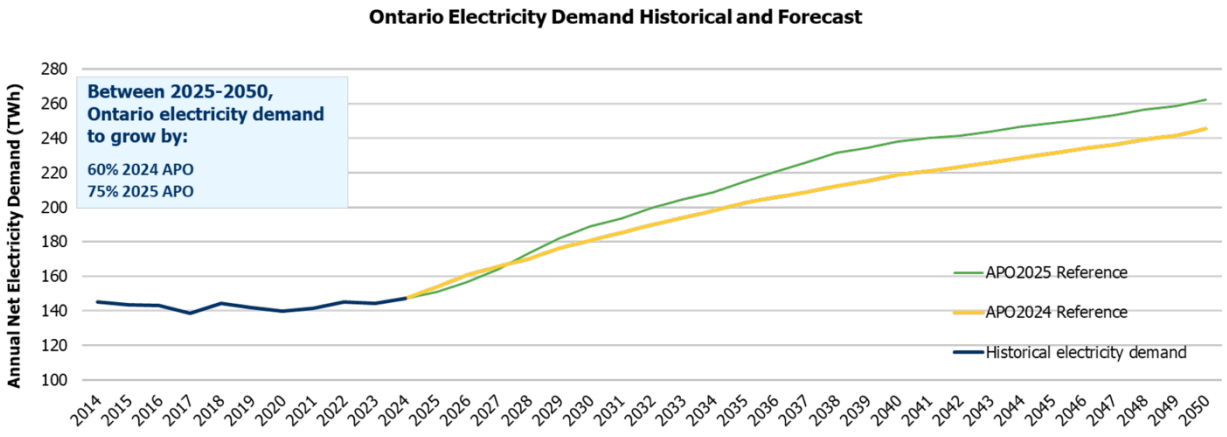
8. Other Important Considerations

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*

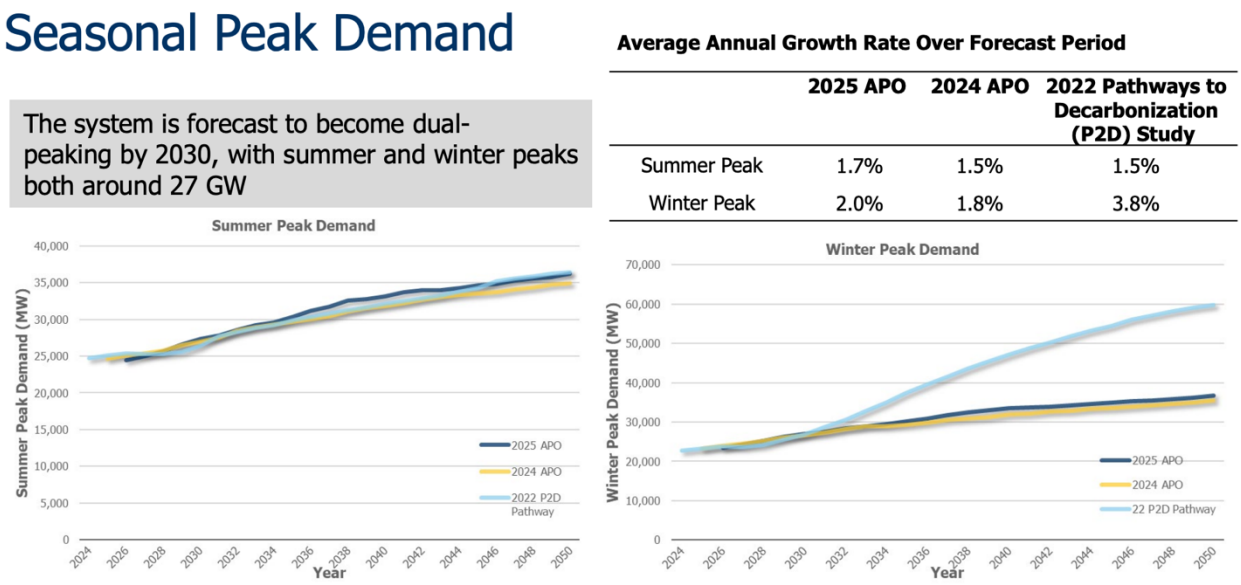
93. The demand forecast underpinning the IESO's 2025 Annual Planning Outlook ("APO") projects total energy demand to grow by 75% by 2050 – up from the 60% growth forecast the IESO included in the 2024 APO. The demand growth is expected to come from multiple sectors, including industrial facilities and 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

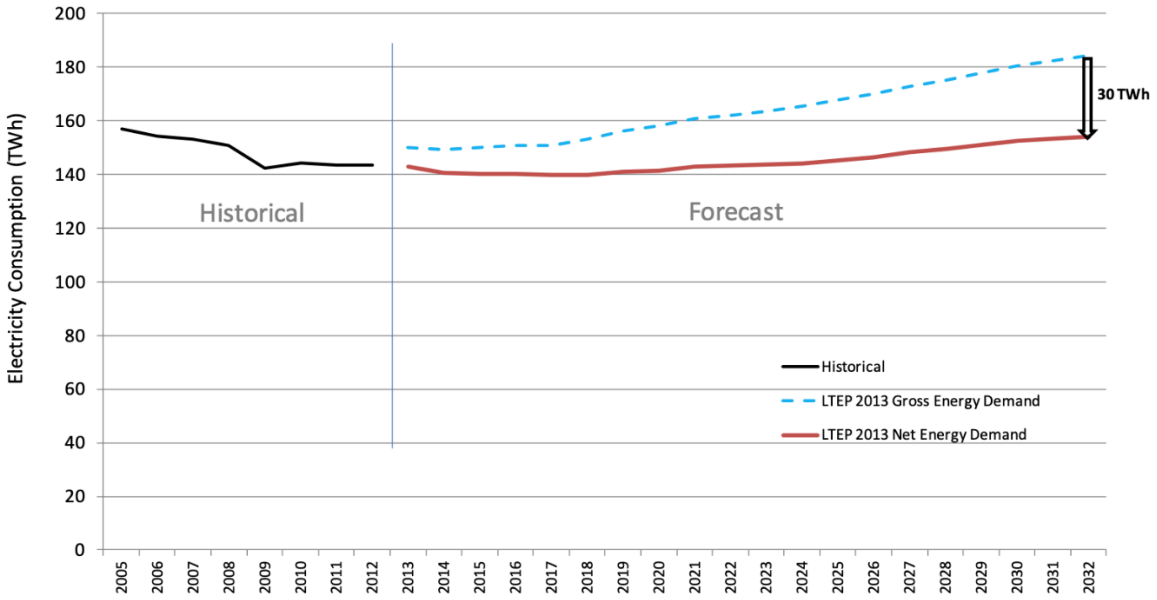


Average Annual Growth Rate Over Forecast Period

	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%

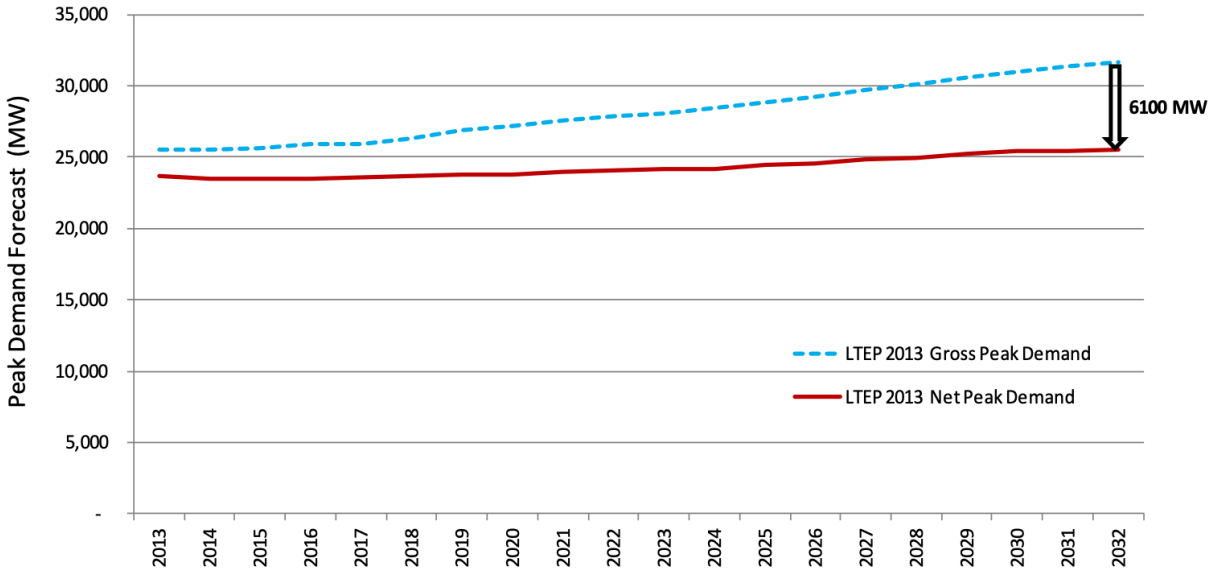
95. The supply needs being forecasted by the IESO are largely unprecedented and mark the largest increase in demand since Market Opening in 2002. For reference, the 2013 Long-Term Energy Plan ("LTEP") from the provincial government was forecasting significantly smaller growth in both energy and peak 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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Detailed Design – Market Settlement: https://www.ieso.ca/-/media/Files/IESO/Document-Library/market-renewal/MRP-Detailed-Design-Market-Settlement-V1.pdf

Detailed Design – Market Power Mitigation: https://www.ieso.ca/-/media/Files/IESO/Document-Library/market-renewal/MRP-Detailed-Design-Market-Power-Mitigation-V1.pdf

Market Manual 14: Market Power Mitigation – Part 14.1 Market Power Mitigation Procedures: https://www.ieso.ca/-/media/Files/IESO/Document-Library/market-renewal/final-alignment-documents/mm-14-1-market-power-mitigation-procedures-20240607.pdf

Market Manual 14: Market Power Mitigation – Part 14.2 Reference Level and Reference Quantity Procedures: https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/imrm/MM-14-2-reference-level-and-reference-quantity-procedures-20231201.pdf

Enhanced Real-time Unit Commitment – High Level Design: https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/eruc/ERUC-High-Level-Design-Aug2019.pdf

Day-Ahead Market – High Level Design: https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/dam/DAM-High-Level-Design-Aug2019.pdf

Single Schedule Market – High Level Design: https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/ssm/SSM-High-Level-Design-Aug2019.pdf

Market Renewal Program – Energy Stream Business Case: https://www.ieso.ca/-/media/Files/IESO/Document-Library/market-renewal/MRP-Energy-Stream-Business-Case-2019.pdf

Market Renewal – Mission and Principles: https://www.ieso.ca/-/media/Files/IESO/Document-Library/market-renewal/market-renewal-mission-principles.pdf

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

Education and Awareness – Energy Workstream High-Level Designs: Non-Quick Start Generators: https://www.ieso.ca/-/media/Files/IESO/Document-Library/public-info-session/2018/EA-non-quick-start-generators.pdf

Introduction to Ontario's Physical Markets: https://www.ieso.ca/-/media/Files/IESO/Document-Library/training/WB-Intro-Ontario-Physical-Markets.ashx

Market Renewal Program Impact on Clean Energy Supply Contracts: Overview and Update: https://www.ieso.ca/-/media/Files/IESO/Document-Library/market-renewal/mr-contract-management-update-ces-generators-draft-term-sheet-20210821.pdf

Market Renewal Impact on CES Contracts Webinar Materials: https://www.ieso.ca/-/media/Files/IESO/Document-Library/market-renewal/MRP-Impact-on-CES-contracts.pdf

Guide to Day Ahead Commitment Process (DACP): https://www.ieso.ca/-/media/Files/IESO/Document-Library/training/TG-Day-Ahead-Commitment-Process.pdf

Workbook Instructions – Reference Levels and Reference Quantities: https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/irl/ref-level-ref-quantities-workbook-instructions-and-faq.ashx

Quick Takes: Real Time Generation Cost Guarantee: https://www.ieso.ca/-/media/Files/IESO/Document-Library/training/QT-Real-Time-Generation-Cost-Guarantee.pdf

Monitoring Report of the IESO-Administered Markets – November 2012 to April 2013: https://www.oeb.ca/oeb/_Documents/MSP/MSP_Report_Nov2012-Apr2013_20140106.pdf

Overview of the IESO-Administered Markets – IESO Training: https://www.ieso.ca/-/media/Files/IESO/Document-Library/training/TG-Overview-of-the-IESO-Administered--Markets.pdf

Non-Quick Starts in Pre-Dispatch Scheduling – November 2019: https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/mrp-edd/edd-20191101-nqs-resources-pre-dispatch-scheduling.pdf

Market Renewal Program Implementation – Q&A Session for GOG-Eligible Non-Quick Start Resources: https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/imrm/imrm-20231003-presentation-for-gog-eligible-nqs.pdf

Market Renewal Program – A Day-in-The-Life for Gas Generators: https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/imrm/ditl/imrm-ditl-gas-generators.pdf

Education and Awareness: Non-Quick Start Generators: https://www.ieso.ca/-/media/Files/IESO/Document-Library/public-info-session/2018/EA-non-quick-start-generators.pdf

Market Manual 9, Part 9.0 – Day Ahead Commitment Process: https://www.ieso.ca/-/media/files/ieso/document-library/market-rules-and-manuals-library/market-manuals/day-ahead-commitment/mm9-dacp-manual.pdf

Market Rule Amendment Proposal – Enhanced Day-Ahead Commitment Process: https://www.ieso.ca/en/sector-participants/change-management/-/media/files/ieso/document-library/mr-amendments/archive/MR-00348-R00-R05.pdf

Market Manual 9, Part 9.4 – Real-time Integration of the DACP: https://www.ieso.ca/-/media/Files/IESO/Document-Library/Market-Rules-and-Manuals-Library/market-manuals/day-ahead-commitment/Real-TimeIntegration.pdf

Market Manual 4, Part 4.6 – Real-time Generation Cost Guarantee Program: https://www.ieso.ca/-/media/723d37052d344d859417de8210521114.ashx

Quick Take – Multi-Interval Optimization: https://www.ieso.ca/-/media/Files/IESO/Document-Library/training/QT-Multi-Interval-Optimization.pdf

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

	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)

	22.15	Ex-Post Mitigation of Physical Withholding (Market Power Mitigation)
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APPENDIX E: CV OF BRADY YAUCH

Brady Yauch
Senior Manager Market and Regulatory Affairs
Power Advisory LLC
55 University Avenue
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
55 University Avenue
Suite 700, P.O. Box 32
Toronto, ON M5J 2H7
Cell: 416-303-8667
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

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

Rules_Form-

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

Authorities

Ontario Energy Board

Commission de l'énergie de l'Ontario

EB-2007-0040

IN THE MATTER OF the *Electricity Act, 1998*, S.O.1998, c.15 (Schedule B);

AND IN THE MATTER OF an Application by the Association of Major Power Consumers in Ontario under section 33 of the *Electricity Act, 1998* for an Order revoking an amendment to the market rules and referring the amendment back to the Independent Electricity System Operator for further consideration, and for an Order staying the operation of the amendment to the market rules pending completion of the Board's review.

DECISION AND ORDER
(Issued April 10, 2007 and as corrected on April 12, 2007)

BEFORE: Gordon Kaiser
Presiding Member and Vice Chair

Pamela Nowina
Member and Vice Chair

Bill Rupert
Member

The Application

On February 9, 2007, the Association of Major Power Consumers in Ontario ("AMPCO") filed with the Ontario Energy Board (the "Board") an Application under section 33(4) of the *Electricity Act, 1998* (the "Act") seeking the review of an amendment to the market rules approved by the Independent Electricity System Operator (the "IESO") on January 17, 2007. The Board has assigned file number EB-2007-0040 to the Application.

The amendment that is the subject matter of the Application is identified as MR-00331-R00: "Specify the Facility Ramping Capability in the Market Schedule" and relates to the ramp rate assumption used in the market pricing algorithm within the IESO-administered markets (the "Amendment").

The specific relief sought in the Application is the following:

- an order under section 33(7) of the Act staying the operation of the Amendment pending completion of the Board's review of the Amendment;

- an order under section 33(9) of the Act revoking the Amendment and referring the amendment back to the IESO for further consideration; and

- an award of costs, such costs to be payable by the IESO.

On February 9, 2007, the Board issued its Notice of Application and Oral Hearing in relation to the Application.

Under section 33(6) of the Act, the Board is required to issue an order that embodies its final decision in this proceeding within 60 days after receiving AMPCO's application.

This is the first application of its kind to proceed to a hearing before, and a decision by, the Board. An earlier application by a different applicant and in relation to a different amendment to the market rules was subsequently withdrawn.

Although the Board has considered the entirety of the record in this proceeding, the Board has summarized the record only to the extent necessary to provide context for those findings.

The Amendment

The Amendment relates to the calculation of the energy price (the market clearing price or "MCP" that is calculated in five-minute intervals) in the real-time energy market administered by the IESO and, more specifically, to a change (from 12x to 3x) in the assumption that is made about the ramping capabilities of generation facilities when determining market prices.

The algorithm that is used to compute MCP – known as the "market schedule" and sometimes referred to as the unconstrained schedule – contains a parameter (the "TradingPeriodLength") that specifies the ramp rate multiplier to be used in determining energy market prices. Ramp rate, which is usually expressed in MW per minute, indicates how quickly the output of a generation facility can be increased or decreased.

Prior to the Amendment, the market rules authorized the IESO (then known as the Independent Electricity Market Operator or IMO)[1] to establish the "TradingPeriodLength" parameter for the pricing algorithm but did not define its value. Prior to market opening, the value of the parameter was set at 60 minutes, which is the equivalent of a 12x ramp rate. Most generation facilities, and in particular those that typically set market prices, can change their output from minimum levels to full output in roughly one hour. The result of the 12x ramp rate multiplier is that the market schedule has since market opening assumed that generation facilities are able to ramp output up or down 12 times faster than is, in fact, the case. It is widely acknowledged that use of the 12x ramp rate multiplier was implemented as a temporary solution to address extreme price excursions that were experienced during testing prior to opening of the wholesale market.

Further examination of the ramp rate multiplier issue was initiated by the IESO in December, 2005. Stakeholder consultations ensued, principally through the Market Pricing Working Group as well as through the IESO's Stakeholder Advisory Committee.

At the end of this examination, the IESO proposed to amend the market rules by setting the value of the "TradingPeriodLength" parameter at 15 minutes, which is the equivalent of a 3x ramp rate. To that end, on December 27, 2006, the IESO published the Amendment for comment. Five submissions were received in response; one from AMPCO opposing the Amendment and four from generators supporting the Amendment as a move in the right direction albeit not as the preferred solution. The Board of Directors of the IESO approved the Amendment on January 17, 2007, and it was published on January 19, 2007. The Amendment was scheduled to go into effect on February 10, 2007, the earliest date permitted by section 33(1) of the Act.

[1] For convenience, this Decision and Order will refer throughout to the IESO even though, at the time relevant to the point under discussion, it may have been called the IMO.

Once implemented, the Amendment would result in the market schedule assuming that generation facilities are able to ramp output up or down 3 times faster than is, in fact, the case.

It is to be noted that the 3x ramp rate multiplier relates solely to the calculation of energy prices. The physical dispatch algorithm (known as the "real-time schedule" and sometimes referred to as the constrained schedule), which is used by the IESO to dispatch facilities to meet market demand in any given interval, reflects the actual ramping capabilities of generation facilities (in other words, the value of the "TradingPeriodLength" parameter is set at 5 minutes, equivalent to a 1x ramp rate).

The role played by, and the impact of, the ramp rate multiplier in the determination of real-time energy prices is discussed further below under the heading "Pricing and Dispatch in the Real-time Energy Market".

The Proceeding

A brief description of the issues and the orders issued by the Board is summarized below.

1. *Stay of Operation of the Amendment*

The Amendment had an effective date of February 10, 2007. AMPCO's arguments in support of its application for an order under section 33(7) of the Act staying the operation of the Amendment pending completion of the Board's review of the Amendment were that: (i) it is in the public interest to order the stay; (ii) there are legitimate concerns with respect to the Amendment that should be considered by the Board; and (iii) the balance of convenience favours a stay.

On February 9, 2007, the IESO filed a letter with the Board indicating that it consented to the stay of the operation of the Amendment, such consent being without prejudice to any arguments that the IESO might make in relation to the Board's review of the Amendment. The IESO noted that it had given due consideration to the balance of convenience and the short duration of the stay given the Board's statutory deadline for completion of its review of the Amendment.

By Order dated February 9, 2007, the Board stayed the operation of the Amendment pending completion of the Board's review of the Amendment and issuance by the Board

of its order embodying its final decision on AMPCO's application for review of the Amendment. The Board noted in particular that the balance of convenience favoured a stay of the operation of the Amendment, particularly given the long history of the ramp rate issue in the IESO-administered markets.

2. Intervenors

The following parties requested and were granted intervenor status in this proceeding: the Association of Power Producers of Ontario ("APPrO"); Coral Energy Canada Inc. ("Coral Energy"); the Electricity Market Investment Group ("EMIG"); Hydro One Networks Inc. ("Hydro One"); the IESO; Ontario Power Generation Inc. ("OPG"); TransAlta Energy Corp. and TransAlta Cogeneration L.P. (collectively "TransAlta"); TransCanada Energy Ltd. ("TransCanada"); and the Vulnerable Energy Consumers Coalition ("VECC").

In addition, the Board received on March 30, 2007 a letter of comment filed by Constellation Energy.

3. *Procedural Order No. 1*

On February 16, 2007, the Board issued its Procedural Order No. 1. In addition to establishing the process and timelines for this proceeding, Procedural Order No. 1 also:

- indicated that cost awards would be made available in this proceeding to eligible intervenors, and solicited written submissions on the issue of the party from whom cost awards should be recovered;

- directed the IESO to file materials associated with the development and adoption of the Amendment; and

- identified the following as the issues to be considered in this proceeding:

    (i) is the Amendment inconsistent with the purposes of the Act?

    (ii) does the Amendment unjustly discriminate against or in favour of a market participant or a class of market participants?

4. *Cost Awards*

Requests for eligibility for an award of costs were made by AMPCO, VECC and APPrO. TransAlta reserved its right to apply for an award of costs should special circumstances arise in the proceeding. In its letter of intervention, the IESO also indicated that it would seek an award of costs.

In response to Procedural Order No. 1, four parties made submissions in relation to the issue of the party from whom cost awards should be recovered. The submissions are summarized in the Board's Procedural Order No. 2 issued on March 9, 2007.
The Board determined that cost awards in this proceeding should be recovered from the IESO, for the reasons stated in Procedural Order No. 2. The Board also determined that VECC, APPrO and AMPCO are eligible for an award of costs in this proceeding, subject to any objections that the IESO might wish to make for consideration by the Board. By letter dated March 16, 2007, the IESO indicated that while it accepts and respects the Board's decision regarding cost eligibility, it reserved the right to ask the Board to limit the amount of costs recoverable by parties objecting to the Amendment in the event that it appears, at the end of the proceeding, that some or all of the grounds for the objection ought not to have been advanced.

5. *Production of Materials by the IESO*

As noted above, among other things Procedural Order No. 1 directed the IESO to file materials associated with the development and adoption of the Amendment. By letter dated March 2, 2007, AMPCO alleged that the IESO's filing in response to Procedural Order No. 1 was deficient in a number of respects. By letter also dated March 2, 2007, the IESO replied to the allegations contained in AMPCO's letter, stating that there is no merit to AMPCO's allegations and that the IESO had produced all of the materials required by Procedural Order No. 1.

In its Procedural Order No. 2, the Board among other things ordered the IESO to produce certain materials, including material prepared by the IESO in the context of the Day Ahead Commitment Process and/or the Day Ahead Market initiative that directly relates to ramp rate (the "DAM/DACP Materials"). In ordering the IESO to produce the DAM/DACP Materials, the Board expressly recognized that the relevance of those Materials to the criteria set out in section 33(9) of the Act, which form the basis of the issues list set out in Procedural Order No. 1, is not clear. Procedural Order No. 2 thus also invited parties to make submissions on the issue of the relevance to this

proceeding of the DAM/DACP Materials, and more specifically to the criteria set out in section 33(9) of the Act and the issues list set out in Procedural Order No. 1.

On March 12, 2007, the IESO filed a letter with the Board in response to Procedural Order No. 2. In that letter, the IESO stated that the nature and extent of the task involved in satisfying the document production requirements of Procedural Order No. 2 makes completion of the task within anything remotely close to the specified timeframe completely impractical. Without waiving any of its rights or accepting the relevance to this proceeding of the materials identified in Procedural Order No. 2, the IESO put forward a proposed plan to meet the Board's information requirements within the requisite timeframes. On March 14, 2007, AMPCO filed a letter with the Board expressing its concerns regarding the IESO's proposed plan. The concerns related principally to the scope of the IESO's production in respect of the subject matter and time period to be covered.

On March 14, 2007, the Board issued its Procedural Order No. 3. The effect of Procedural Order No. 3 was to revise the nature of the production required of the IESO under Procedural Order No. 2, generally in line with the proposed plan submitted by the IESO in its letter of March 12, 2007 but with the exception that the production should cover a longer period than that proposed by the IESO.

6. *Technical Conference*

Procedural Order No. 1 made provision for a technical conference to be held in this proceeding. On March 20, 2007, and in response to inquiries received by certain parties, Board staff communicated with the parties to confirm whether they wished to proceed with the technical conference. Based on the responses received to that communication, the Board decided to cancel the technical conference and the parties were so advised by Board staff on March 21, 2007.

7. *Submissions on the "Relevance Issue"*

On March 21, 2007, AMPCO filed with the Board a letter setting out a proposal for submissions on the issue of the relevance of certain materials to this proceeding. As noted above, in its Procedural Order No. 2 the Board invited parties to make submissions on the relevance of the DAM/DACP Materials. AMPCO's proposal, made with the consent of the IESO, was to the effect that AMPCO would provide the Board and all parties with a "comprehensive submission on the relevance of materials

produced by the IESO in relation to a central theme contained in AMPCO's application: "that the Amendment violates fundamental principles of procedural fairness". The proposal also suggested that, rather than filing submissions in accordance with Procedural Order No. 2, parties should await production of AMPCO's comprehensive submission and respond to that document.

On March 22, 2007, the Board issued its Procedural Order No. 4 setting out the timeframe for the filing of AMPCO's submissions on relevance. The Board encouraged intervenors to make written submissions in response to those of AMPCO but, given the imminence of the commencement of the oral hearing, indicated that it would allow all intervenors to make oral submissions on the relevance issue at the beginning of the oral hearing.

Written submissions on relevance were filed by AMPCO, the IESO, APPrO and Coral Energy. The positions of the parties are summarized below under the heading "The Board's Mandate".

8. *The Oral Hearing and Final Written Argument*

The Board held an oral hearing in this proceeding, commencing on March 29, 2007 and concluding on March 30, 2007. The first day of the hearing was devoted almost exclusively to submissions by the parties on the "relevance issue", as described in greater detail below under the heading "The Board's Mandate". On the second day of the hearing, witnesses gave evidence on behalf of AMPCO, the IESO, APPrO and TransCanada, principally in relation to the nature and impact or effect of the Amendment. The position of the parties in this regard is discussed in greater detail below under the heading "The Impact of the Amendment".

During the hearing, proposals were also made by certain of the parties in relation to the filing of final written argument, and these were accepted by the Board. AMPCO filed its final written argument on April 2, 2007. VECC filed its final written argument on April 3, 2007. The following parties filed their final written argument on April 4, 2007: the IESO; APPrO; and TransCanada. OPG filed a letter with the Board indicating its support for the final argument filed by APPrO. Coral Energy did not file final written argument, but did indicate during the oral hearing that it would address the substantive issues associated with the Amendment through APPrO. AMPCO filed its written reply argument on April 5, 2007.

The Board's Mandate

The "relevance issue", as it has been referred to in this proceeding, arose initially in relation to the DAM/DACP Materials. As stated in Procedural Order No. 4, the issue is relevance of materials – and hence of the position or argument that the materials support – relative to the criteria set out in section 33(9) of the Act. This issue, of necessity, requires consideration of the scope of the Board's mandate on applications to review amendments to the market rules under section 33 of the Act.

As the proceeding progressed, it became clearer that AMPCO's views as to the scope of the Board's mandate differs markedly from the views of other parties. A number of the concerns raised by AMPCO regarding the Amendment relate not to the impact or effect of the Amendment, but rather to the process by which the Amendment was made by the IESO. Many of the materials filed by the IESO in response to the Board's Procedural Orders are relevant to those concerns, but have little or no relevance to the issue of the impact or effect of the Amendment.

The position of the parties in relation to the scope of the Board's mandate, as expressed in the written submissions filed in response to Procedural Order No. 4 and/or in oral submissions made at the commencement of the oral hearing, may be summarized as follows.

AMPCO's position is that the Board's mandate is not limited to the grounds set out in section 33(9) of the Act. Rather, the Board has a "plenary review jurisdiction" that would allow the Board to address what AMPCO alleges as significant failures of procedural fairness by the IESO. In support of its position, AMPCO referred to and relied on sections 33(4), 33(5) and 33(6) of the Act, on section 19(4) of the *Ontario Energy Board Act, 1998*, on the Board's authority to determine all questions of law and fact in all matters within the Board's jurisdiction, and on the Board's public interest role. On that basis, in AMPCO's view the criteria expressed in section 33(9) of the Act are better understood as the two instances in which the legislature has directed the Board on how it must exercise its review discretion, leaving the Board otherwise able to exercise its review discretion as the Board sees fit.

By contrast, the position of the IESO, APPrO, Coral, OPG and TransCanada is that the Board's mandate is limited by section 33(9) of the Act to a determination of whether (a) the amendment is inconsistent with the purposes of the Act; or (b) the amendment unjustly discriminates against or in favour of a market participant or a class of market

participants. On that basis, whether the IESO has, and breached, a common law duty of procedural fairness or acted in a manner giving rise to a reasonable apprehension of bias (both of which allegations were denied by the IESO), are not matters for consideration by the Board on a market rule amendment review application under section 33 of the Act. Materials produced by the IESO that are relevant only to the IESO's processes in making the Amendment should therefore be disregarded. The IESO also specifically requested that the Board strike AMPCO's March 26, 2007 submission from the record.

On March 29, 2007, the Board rendered an oral decision on this issue. Specifically, the Board determined that its mandate under section 33 of the Act is limited to an examination of the market rule amendment against the criteria set out in section 33(9) the Act. The Board also ordered that any evidence relating to the IESO's stakeholdering process, including AMPCO's March 26, 2007 submission, be struck from the record. An excerpt from the transcript of the oral hearing that contains the Board's decision and order in this regard is set out in Appendix A to this Decision and Order.

The parties agreed to, and filed with the Board, a list of the materials affected by the Board's decision (i.e., those to be struck from the record and those to remain on the record).

The Impact of the Amendment

It remains for the Board to determine whether the Amendment is inconsistent with the purposes of the Act or unjustly discriminates against or in favour of a market participant or a class of market participants.

A brief summary of the position of the parties is set out below, followed by the Board's findings.

In order to better understand the position of the parties, however, it is necessary to provide some further context around the setting of prices in the IESO-administered energy market and the role that the ramp rate multiplier plays, if only at a high and simplified level.

1. *Pricing and Dispatch in the Real-time Energy Market*

The MCP, which is calculated in five-minute intervals, is determined using a market schedule (pricing algorithm) that calculates the price based on the most economical offers submitted by generators that would satisfy the demand for energy in a particular five-minute interval. Dispatchable generators receive the MCP for their output, and dispatchable loads pay MCP for the energy they consume. All other generators and loads receive or pay, respectively, the Hourly Ontario Energy Price ("HOEP"). HOEP is a simple average of the 12 MCPs determined for the hour. Ontario currently has a uniform pricing system and MCP (and thus HOEP) are the same everywhere in the province. The introduction of locational marginal pricing for the province, which has long been the subject of discussion, is not expected to occur at least in the short term. However, the IESO does calculate what the prices would be in different locations were locational marginal pricing to be in place. These are referred to as "shadow prices".

Three aspects of the market schedule are of particular relevance to this proceeding:

- the market schedule is "myopic", in that it ignores expected demand in future intervals and sets the MCP based solely on demand conditions in each five-minute interval;

- the market schedule ignores transmission constraints, and assumes for pricing purposes that the cheapest available generation facility anywhere in Ontario is available to satisfy demand in any interval when, in fact, it may be unavailable due to transmission constraints; and

- the market schedule assumes for pricing purposes that generation facilities are able to ramp output up or down faster than they might actually be able to do so (by a factor of 12 currently or by a factor of 3 under the Amendment).

By contrast, the algorithm used by the IESO to dispatch facilities has the following characteristics:

- the dispatch algorithm has, since 2004, incorporated multi-interval optimization ("MIO"), which "looks ahead" to expected demand in future five-minute intervals;

- the dispatch algorithm takes account of all physical constraints on the system; and

- the dispatch algorithm respects the actual ramping capabilities of generation facilities.

The result is that MCP does not necessarily reflect what the prices would have been had the prices been determined on the basis of the offers submitted by generation facilities that are actually dispatched to provide energy to meet demand in a given five-minute interval. The ramp rate multiplier allows the market schedule to set prices on the basis of generation facilities that are cheaper but unavailable due to actual ramping restrictions, and as a result reduces both price volatility and the average level of prices. The same can be said for the market schedule assumption that the system is unconstrained.

A consequence of the lack of complete alignment between the pricing algorithm and the dispatch algorithm is that generation facilities that were assumed by the market schedule to be supplying energy in a five-minute interval might not in fact be dispatched due to the presence of transmission or ramping constraints. A generation facility may have to be dispatched even though it had offered to supply electricity at a price that is higher than HOEP. These generation facilities will be "constrained on", and under the market rules are entitled to an additional payment referred to as a Congestion Management Settlement Credit ("CMSC") payment. Similarly, when a cheaper generation facility is not dispatched due to the presence of transmission constraints or because it can ramp down more quickly than a more expensive generation facility, the cheaper facility will be "constrained off" and also entitled to a CMSC payment. In both cases, the CMSC payment reflects the difference between HOEP and the offer made by the generation facility that has been constrained on or constrained off, as the case may be. CMSC payments are not reflected in the energy price, but are recovered through uplift charges from wholesale market participants on a pro-rata basis based on their energy consumption at the time at which the CMSC payments were incurred.

2. Position of the Parties on the Impact of the Amendment

The following summary is based principally on the final arguments filed by the parties. For the most part, these largely reflect the tenor of each party's participation in this proceeding.

The position of the parties to this proceeding fall into two distinct camps: AMPCO and VECC oppose the Amendment while the IESO, APPrO, Coral Energy (through APPrO),

OPG and TransCanada support it. The letter of comment received from Constellation Energy also supports the Amendment. TransAlta was not an active participant in this proceeding, but is one of the generators that indicated its support for the Amendment as an interim solution in response to the IESO's request for submissions referred to above. EMIG (of which Coral Energy and Constellation Energy Group Inc. are members) was also not an active participant in this proceeding, but noted in its letter of intervention its belief that "in order to support new private investment in generation, Ontario must transition towards a competitive market where prices reflect the true cost of power". Hydro One did not take a position in this proceeding.

A number of the arguments made by AMPCO and VECC challenge the validity or reliability of the IESO's assessment of the costs and benefits associated with the Amendment, and are therefore better understood if the position of the parties supporting the Amendment is presented first.

Parties Supporting the Amendment

Active participants in this proceeding that support the Amendment assert that the Amendment is consistent with the purposes of the Act and does not unjustly discriminate against or in favour of a market participant or a class of market participants. Certain parties have added that the evidence in this proceeding is overwhelmingly to that effect.

The IESO's position is that the Amendment is consistent with, and will promote, a number of the purposes of the Act. Specifically, the IESO submits that the Amendment will: enhance overall reliability, better protecting the interests of consumers in that regard (sections 1(a) and 1(f) of the Act); encourage conservation and demand management (sections 1(b) and 1(c) of the Act); promote economic efficiency (section 1(g) of the Act); and cultivate a financially viable electricity industry (section 1(i) of the Act). According to the IESO, the Amendment will contribute to the achievement of these objectives by: more closely aligning the dispatch and pricing algorithms; resulting in more accurate price signals for consumers and producers; reducing uneconomic exports out of Ontario with resulting efficiency gains realized through the mechanism of export arbitrage; providing immediate efficiency gains for the Province; reducing fossil fuel generation; and achieving a significant improvement in efficiency for the Ontario market.

The IESO further submits that the Amendment, a superior solution to the available alternatives (including incorporation of MIO in the pricing algorithm), will be simple and inexpensive to implement and will achieve the noted benefits with minimal, if any, impact on average prices for consumers. The IESO has estimated that the impact of the Amendment on HOEP will be an average 2.6 percent increase. However, the IESO has also estimated that the impact on consumer bills will be mitigated by: the export arbitrage response that is expected to follow implementation of the Amendment; the global adjustment; the rebate that is currently paid out on revenues earned by OPG on its non-prescribed assets (the "OPG Rebate"); savings in CMSC payments; and savings in Intertie Offer Guarantee payments (these being payments made to importers to reduce price risks for imports that result from the fact that they are scheduled based on pre-dispatch prices but settled on the basis of real-time prices). After accounting for such mitigation, and based on 2006 market prices, the impact of the Amendment would, according to the IESO, vary from a net cost of $6.68 million or 0.004 cents/kWh (assuming an export arbitrage response of 50%, which the IESO considers conservative) to a net saving of approximately $13 million or 0.008 cents/kWh (assuming an export arbitrage response of 100%). As a supplementary mitigation measure, the IESO intends to disburse surplus funds from the transmission rights clearing account (the "TR Clearing Account") over 12 consecutive months to begin in conjunction with implementation of the Amendment.

With respect to the issue of unjust discrimination, the IESO argues that discrimination, in the context of a market for electricity, refers to economic discrimination. As such, more must be involved than an economic advantage accruing to one party rather than the other. The IESO further states that, by lessening subsidies and better aligning prices and dispatch costs, the Amendment plainly lessens inappropriate economic treatment of market participants.

Similar to the IESO, APPrO submits that improvements resulting from implementation of the Amendment are consistent with the purposes set out in sections 1(b), 1(c), 1(f), 1(g) and 1(i) of the Act. According to APPrO, the Amendment addresses many of the challenges and inefficiencies resulting from the use of the 12x ramp rate multiplier by creating just price signals for generators and loads, and does so with minimal, if any, customer cost impacts. APPrO also argues that the effects resulting from the 12x ramp rate multiplier are prejudicial to, and discriminate against, consumers and suppliers. APPrO states that, by more closely aligning the pricing algorithm with the dispatch algorithm, the Amendment would mitigate those prejudicial and discriminatory effects

(such effects including that consumers are not paying the true cost of the electricity they consume and are paying for inefficiencies through uplift charges).

TransCanada's position is that the Amendment will improve the operation of Ontario's competitive electricity market and, since many of the purposes of the Act have as their object the promotion of a competitive market, improvements to the market support the purposes of the Act. According to TransCanada, by moving the market closer to real prices, the Amendment will also specifically encourage conservation (section 1(b) of the Act) and promote the use of cleaner energy sources (section 1(d) of the Act). TransCanada also submits that market efficiency will be promoted by: more closely aligning the pricing and dispatch algorithms; increasing the internal consistency of the market rules; improving price signals and inducing more efficient investment; and improving price transparency and reducing less transparent uplift payments (by reducing CMSC payments). While not a perfect solution, in TransCanada's view the Amendment represents an important step in the right direction.

On the issue of unjust discrimination, TransCanada agrees with the view expressed by Coral Energy in submissions made before and during the oral hearing to the effect that "unjust" discrimination equates with "inefficient" discrimination.

Parties Opposing the Amendment

AMPCO and VECC take the position that the Amendment fails when considered in light of the criteria set out in section 33(9) of the Act, and should therefore be revoked and referred back to the IESO for further consideration.

AMPCO's position is that the Amendment is inconsistent with certain of the purposes of the Act. The purposes of the Act that underlie this position are: (i) ensuring the adequacy, safety, sustainability and reliability of electricity supply in Ontario through responsible planning and management of electricity resources, supply and demand (section 1(a) of the Act); and (ii) protecting the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service (section 1(f) of the Act). AMPCO also submits that the Amendment unjustly discriminates against consumers (by increasing prices) and in favour of generators (by providing "windfall profits" to generators – such as nuclear generators – that are unable to respond quickly to changing demand conditions).

In support of its position, AMPCO submits that the IESO is not at liberty to pick and choose the purposes of the Act that it will further while ignoring others in favour of perceived improvements in efficiency. The Act does not assign differing weights or priorities to the various purposes of the Act and, if anything, the protection of the interests of consumers has been given priority.

AMPCO also submits that the IESO's estimates of the costs and benefits of moving to a 3x ramp rate multiplier in terms of determining the wealth transfer implied by the Amendment are unreliable. According to AMPCO, the efficiency gains flowing from the Amendment, as articulated by the IESO and other parties, are: (i) not supported by economic theory having regard to the "Theory of the Second Best"; (ii) based on the mistaken view that uneconomic exports are principally the result of the 12x ramp rate multiplier rather than being largely attributable to Ontario's uniform pricing structure; and (iii) overstated. AMPCO states that, by contrast, the impact of the Amendment on consumers – a price impact variously estimated by the IESO at approximately $225 million, $197 million, $112 million and $100 million depending on whether the effect of arbitrage is taken into account – has been understated. AMPCO notes that a number of the price mitigation mechanisms identified by the IESO are of short (the OPG Rebate and the disbursement of funds from the TR Clearing Account) or uncertain (the global adjustment) duration or are speculative (export arbitrage), and a longer term price mitigation strategy is required. AMPCO also notes that the 3x ramp rate multiplier solution is inferior to incorporation of MIO in the pricing algorithm, which is a superior solution that could be implemented at a modest cost, and is not the preferred option identified by any market participant.

In its reply argument, AMPCO submits that the evidence in this proceeding does not, contrary to the position expressed by APPrO, answer the question of whether the Amendment will result in a HOEP that more closely approximates the price that would result were the pricing and dispatch algorithms perfectly aligned. AMPCO also submits that the evidence does not address what the "true cost" of electricity might be, nor how such notion compares based on the current HOEP versus HOEP calculated on the basis of the Amendment. Moreover, given the hybrid nature of the market, prices are not in AMPCO's view expected to have more than a marginal impact on investment decisions. AMPCO also notes that, contrary to the view articulated by TransCanada, the Act does not have as one of its objectives the promotion of a competitive market.

VECC's position is that the Amendment unjustly discriminates against consumers because it results in a pricing algorithm that moves away from, rather than towards, the

prices generated by the IESO's dispatch algorithm, resulting in overall inefficiency in the setting of HOEP by unjustifiably increasing the prices consumers pay on a province-wide basis. While agreeing that the Board's role is not to "remake" the IESO's decision in relation to the Amendment, VECC submits that the Board must determine whether the decision-making process was sound and led to a reasonable result in that: the issue was clearly defined; the criteria used by the IESO were comprehensive and consistent with the purposes of the Act; and the criteria were applied on a consistent and balanced basis throughout the decision-making process. VECC argues that the IESO's characterization of the issue changed over time from a focus on the differences between the pricing algorithm and the dispatch algorithm to a focus on inefficient exports. According to VECC, there is no confidence that the Amendment is the best way to address the newly framed issue without unjustly discriminating against consumers. In VECC's view, the IESO should therefore be directed to reconsider alternative solutions to the inefficient export issue that do not unjustly discriminate against consumers by inexplicably raising domestic prices.

VECC also expressed concern regarding use of the IESO's cost/benefit analysis as the measure of economic efficiency for changes in rules dealing with the market schedule and the determination of energy prices, noting that: uneconomic exports are largely the result of the fact that Ontario has uniform pricing; the IESO has narrowly redefined the issue of economic efficiency as reducing exports to New York; certain of the benefits that the IESO has identified in relation to the Amendment are unsubstantiated; and any amendment to the market rules that increased market prices would be judged as economically efficient when based on the IESO's analytical framework.

3. *Position of the Parties on the Burden of Proof*

An issue that arose most squarely in the exchange of final written argument is the question of which party bears the burden of proof in an application under section 33 of the Act.

Certain references in the IESO's final written argument make it clear that, in the IESO's view, in an application under section 33 of the Act the burden of proof is on the applicant to demonstrate that the market rule amendment is inconsistent with the purposes of the Act or is unjustly discriminatory.

AMPCO takes a different view, and submits that the burden of proof is ultimately on the IESO to show that the market rule amendment at issue in fact satisfies the test to be

applied by the Board as set out in section 33(9) of the Act. In support of that view, AMPCO notes that a market rule amendment review is fundamentally different from a more typical proceeding before the Board in that, among other things, applicants have no ability to pursue the relief of their choice by seeking an alternative or different amendment to the one adopted by the Board of Directors of the IESO. AMPCO also notes that the 60-day timeline within which the Board must issue its order on an application under section 33 of the Act supports AMPCO's position on the burden of proof issue. It would be patently unreasonable to expect that any applicant could develop a traditional applicant's filing complete with a full array of econometric and other analyses in the time allowed.

4. *Board Findings*

a. The Burden of Proof

In applications before the Board, the burden of proof is typically on the applicant to satisfy the Board that the requested relief should be granted. The Board certainly expects that the IESO will participate fully in proceedings relating to applications under section 33 of the Act in support of the amendment that is under review. However, the Board has heard no compelling reason that would cause it to take a different approach and place the burden of proof on the IESO in the circumstances of this case.

b. The Merit of Addressing the 12x Ramp Rate Multiplier Issue

Before turning to an examination of the impact or effect of the Amendment, the Board considers it useful to provide further context regarding the history and impact of the 12x ramp rate multiplier in the marketplace. Several parties noted that, as the wholesale market was designed for implementation at market opening, inputs to both the pricing algorithm and the dispatch algorithm were aligned in relation to the value to be used to reflect the ramping capabilities of generation facilities (in both algorithms, the value of the "TradingPeriodLength" was set at 5 minutes). To this day, that remains the case for the dispatch algorithm. As noted above, however, prior to market opening the market rules were amended to allow the IESO to set a different value for the "TradingPeriodLength" parameter in the pricing algorithm as a temporary measure to address extreme real-time price excursions that occurred during market testing. This is reflected in the "Explanation for Amendment" contained in market rule amendment proposal MR-00189-R00, dated April 16, 2002, which proposed the amendment to the

market rules that would allow the IMO the discretion to set the value of the TradingPeriodLength parameter in the pricing algorithm:

> The proposed amendment would permit the IMO to establish a longer Trading Period Length in the market schedule (unconstrained) to overcome the [price excursion] problems identified above. With a longer Trading Period Length within the market schedule (unconstrained), generation facilities will have large ramping capability and there will be less need to select additional higher cost resources to meet the increasing demand. As a result, less extreme price excursions will occur.
>
> The real-time schedule (constrained) will continue to use the 5 minute Trading Period Length. Therefore, discrepancies will increase between the real-time schedule and the market schedule (unconstrained). As a consequence, congestion management settlement credit (CMSC) payments will increase. However, the decreases in energy prices, resulting from the change in the ramp time in the market schedule, are expected to offset increases in CMSC payments.
>
> It should be noted that using a longer Trading Period Length in the determination of the market schedule is judged to be a transitional provision. It is expected that a longer term solution will need to be considered which could include a day-ahead market with unit commitment, increased generator self-scheduling, contracted ramp capability, or multi-period optimization.

The Board has not heard any evidence in this proceeding that would point to the introduction of the 12x ramp rate multiplier as having a basis rooted in market economics. To the contrary, the evidence in this proceeding is that the 12x ramp rate multiplier distorts wholesale market prices downwards and engenders adverse consequences for the marketplace in the form of generation and demand side inefficiencies. For example, dampened wholesale prices diminish incentives for conservation, load management and demand side management. The evidence in this proceeding is also that the 12x ramp rate multiplier contributes to inefficient exports. Inefficient exports, in turn, can increase the need for coal-fired generation to meet Ontario demand and thereby contribute to increased emissions. These adverse consequences were identified and discussed at some length in the evidence filed by, and the testimony given on behalf of, the IESO and APPrO, and are also discussed in the evidence filed by TransCanada. That adverse consequences flow from the 12x ramp rate multiplier was not seriously contested by evidence to the contrary filed by

AMPCO, although AMPCO did challenge the strength of any causal connection between the 12x ramp rate multiplier and inefficient exports.

The Board also notes that the 12x ramp rate multiplier issue has been the subject of comment by the Market Surveillance Panel. Specifically, the potential adverse market impact of the 12x ramp rate multiplier has been referred to or discussed in the following Market Surveillance Panel semi-annual monitoring reports, which were referred to by a number of parties to this proceeding: December 13, 2003 (covering May 2002 to October 2003); December 13, 2004 (covering the period May to October 2004); June 9, 2005 (covering the period November 2004 to April 2005); June 14, 2006 (covering the period November 2005 to April 2006); and December 13, 2006 (covering the period May to October 2006).

For example, after concluding that a significant portion of the difference between the constrained and unconstrained real-time prices, and of the remaining difference between HOEP and the unconstrained pre-dispatch price, is due to the 12x ramp rate assumption, the Market Surveillance Panel stated as follows in its December 13, 2004 report (at page 66):

> The Panel is of the view that the continued understatement of the HOEP leads to inefficient decisions by both loads and generators in both the short-term and the long-term. This takes the form of an inefficient load profile and of under-investment in both conservation and generation.
>
> With respect to the argument that the assumption that ramp rates are 12-times their true value results in a more stable HOEP, the Panel recognizes that price stability can be beneficial to market participants. The Panel observes, however, that it is open to market participants to insulate themselves contractually from price variation. Moreover, price volatility presents a profit opportunity for more price responsive generation and loads. To the extent that it is efficient to do so, volatility can be reduced by the actions of market participants. This is much better, in the Panel's view, than suppressing price variation by artificial means, especially when this has the side effect of understating the average price. The Panel strongly recommends that actual ramp rates be used to determine the HOEP.

Eighteen months later, the Market Surveillance Panel further commented on the issue in its June 14, 2006 report (at page 79) as follows:

> For these and possibly other reasons, arbitrage between Ontario and New York is focused on the HOEP. The result is inefficient exports and the effective extension of the cross-subsidy inherent in Ontario's uniform price regime to New York loads. This problem has been exacerbated by market rules that, other things being equal, would have reduced the HOEP relative to prices in the constrained schedule. For example, the 12 times ramp rate assumption, which has the appearance of systematically lowering the HOEP (i.e., because it removes ramp effects in price), may simply lead to more exports than would otherwise occur.

In its most recent report, dated December 13, 2006, the Market Surveillance Panel stated as follows on page 106:

> There are two major causes of socially inefficient exports from Ontario to New York. First, like privately inefficient exports, the lack of accurate price signals or information can lead to "guessing wrong" and hence socially inefficient exports ex post. Improvements in price signals should result in a higher frequency of socially efficient exports. Socially inefficient exports can also occur, however, if there are defects in the market design. Ontario's uniform pricing regime is poorly designed in the sense that it admits to the possibility that the prices that exporters pay do not reflect the incremental cost of supply. Other aspects of the unconstrained pricing algorithm such as the 12 times ramp rate assumption can further misalign the HOEP and the relevant nodal prices thereby contributing to the potential for ex post socially inefficient exports… (footnote omitted)

And again at pages 147 and 148:

> Moreover, with the Global Adjustment dampening the redistributive effects of changes in HOEP and mitigating any harm that might be said to be visited upon consumers from potentially higher HOEP, the Panel contends that there may be no better time than now to address the remaining sources of inefficiency in the design of the Ontario spot market. Artificially reducing the HOEP, as is the outcome under the current market design, simply means that consumers pay more (or receive a smaller rebate) through the Global Adjustment, all the while inducing market inefficiencies from which all Ontarians lose.

The real-time price signals generated by an efficient wholesale market are central to the economic success of the new hybrid market for several reasons:

- First, the real time production and consumption decisions of many wholesale market participants will continue to be guided by real-time prices. If these price signals continue to ignore certain system realities such as transmission constraints or the actual ramping capabilities of generation facilities, they will at times induce these participants to make decisions that reduce the short-term dispatch efficiency. As we have indicated in Chapter 3, factors such as the uniform pricing system and the 12 times ramp rate assumption create a wedge between the HOEP and local shadow prices. This can result in inefficient production and consumption decisions such as the inefficient exports from Ontario to New York that we began documenting in our last report….(footnote omitted)

- Second, even though long-term investment will be guided through central planning in the near term, price signals from an efficient wholesale market can and should play an important role in guiding this planning process…Furthermore, as we have argued above, attempts to subsidize consumers by suppressing real-time prices leads to over-consumption and could ultimately lead to over-investment by the planners at [the Ontario Power Authority].

These comments reinforce the evidence in this proceeding as to the inefficiencies to which the 12x ramp rate multiplier contributes.

The observations of the Market Surveillance Panel in its most recent (December 13, 2006) report also support the assertion made by the IESO and others that addressing efficiency of the market remains a relevant objective even in the context of the hybrid framework under which Ontario's electricity sector operates at this time. Even AMPCO's expert witness, Dr. Murphy, who questioned the relevance or merits of the Amendment in light of the evolution of the market to a hybrid structure, conceded on cross-examination that improvements in wholesale market efficiency and accurate price signals are important even in a hybrid market.

The Board accepts that the 12x ramp rate multiplier, introduced as a temporary measure, has price distorting effects that can and do engender inefficiencies. The Board therefore also accepts that, in principle, there is merit in addressing the 12x ramp

rate multiplier issue if and to the extent that efficiency improvements can be expected to result, and that this is so even in the context of the hybrid market.

c. Evaluation of the Amendment as a Solution

The IESO has put forward credible evidence that the Amendment will result in greater efficiency in the IESO's real-time market as compared to the status quo. The benefits from this improved efficiency include, but are not limited to, reduced uneconomic exports to New York. The impact of this latter benefit is quantifiable, and has been quantified by the IESO. The other benefits are less easily quantified, but bear consideration nonetheless.

The Board does not agree with AMPCO's argument that the Amendment is inconsistent with the purposes of the Act and that the IESO has selectively chosen the purposes of the Act it will further while ignoring others. AMPCO asserts that the Amendment is contrary to section 1(a) of the Act ("responsible planning and management of electricity resources, supply and demand"). The Board concurs with the IESO's view that greater economic efficiency will further that objective. AMPCO also argues that the Amendment is inconsistent with section 1(f) of the Act ("protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service"). As discussed more fully below, the Board finds that the IESO has carefully considered the impact of the Amendment on consumers' average bills and determined that the impact is likely to be relatively modest. It may even be positive. The IESO has also noted that, while there may be a modest impact on consumers' bills, the Amendment is consistent with the purpose of protecting the interests of consumers with respect to the adequacy and reliability of supply.

There is no evidence before the Board in this proceeding that would lead the Board to take issue with the assertion made by the IESO and others that improvements in the economic efficiency of the electricity system in Ontario will promote adequacy and reliability of supply by providing more accurate price signals and triggering more appropriate price responsive behaviour. The same can be said for the assertions that the Amendment will encourage conservation, load management and demand side management and will, by reducing inefficient exports, also reduce the need for coal-fired generation to meet Ontario demand and thereby contribute to a lessening of emissions.

AMPCO and VECC both assert that the "3x myopic" Amendment is, by the IESO's own submission, inferior to a "1x MIO" solution. They support this view by reference to

documents that were prepared by the IESO at various times in the Amendment development process. They submit that this is a valid basis on which the Board should revoke the Amendment.

The Board does not accept that view. Although it is obvious that the IESO reviewed several alternatives in the course of developing the Amendment, it has consistently taken the position in this proceeding that a "3x myopic" rule is superior to a "1x MIO" option. This conclusion appears in the document issued by the Board of Directors of the IESO when the Amendment was approved, and it is supported by the IESO's and APPrO's experts. Other than referring to earlier assessments that the IESO does not currently support, AMPCO and VECC provided no evidence that "1x MIO" is a superior solution.

d. The Anticipated Impact on Consumer Bills

The Board has also considered the possible impact of the Amendment on consumers' electricity bills.

As noted above, the IESO has calculated that the net annual cost to consumers of adopting the 3x ramp rate assumption in the pricing algorithm is $6.68 million, or 0.004 cents/kWh. That calculation is based on the following assumptions and estimates:

- an average annual HOEP of $49 per MWh (the average price in 2006);
- an increase of 2.6% in the average HOEP as a result of the Amendment, before consideration of mitigating factors;
- mitigation of 50% of the estimate increase in HOEP due to "export arbitrage";
- mitigation of 80% of the net price increase (that is, after the export arbitrage effect) due to the global adjustment and the OPG Rebate; and
- reductions in CMSC payments and Intertie Offer Guarantees that are paid through uplift charges.

In its calculation of the net consumer impact, the IESO also takes into account a planned distribution to consumers of approximately $54 million from the IESO's TR Clearing Account. The Board does not believe that this particular distribution is

appropriately considered as a mitigation measure in relation to the Amendment. Elimination of this particular mitigation measure does not affect the Board's overall assessment of the Amendment.

Dr. Rivard of the IESO testified that, on the basis of additional analysis on the elasticity of export response, the export arbitrage effect on HOEP would likely be higher than 50%, which would reduce further the net cost of the Amendment to consumers. He noted that were the export arbitrage effect to reach approximately 65%, and keeping the other assumptions the same, the impact of the Amendment would be a net reduction in consumers' bills.

AMPCO disputes most of the assumptions and estimates that underlie the IESO's calculations. It claims that the IESO's estimates are unreliable, although it provided little evidence about the estimates it believes should be used.

Predicting the net effect of the Amendment on consumer's bills is a complex exercise and is not something the Board believes can be done with precision. The Board does, however, view the IESO's calculation as an indicator of the order of magnitude of the net effect of the Amendment. The Board agrees with AMPCO that the base price of $49 per MWh, which is the starting point of the IESO's calculation, is low by historical standards. The Board notes, however, that the IESO provided additional information on a range of net consumer costs using higher average HOEPs. The Board also acknowledges AMPCO's comment that the OPG Rebate is scheduled to expire in two years. Even if the OPG Rebate is discontinued at that time, the IESO has estimated that the global adjustment would still provide significant price mitigation, approximately 60% compared to the current 80% from the combined global adjustment and OPG Rebate.

The Board finds that the expected impact on consumers' bills is relatively modest. The IESO's published calculation shows a very minor impact – just 0.004 cents/kWh – based on estimates that the IESO considers to be conservative. Even if a higher base price were used (an average annual HOEP of $70 per MWh based on 2005 prices), and assuming no replacement for or extension of the OPG Rebate in two years, the estimated net impact would be larger but still relatively small. The difference resulting from the use of a higher base price relative to use of the lower one would be much less than 1/10th of a cent/kWh.

e. Conclusions

The Board concludes that the efficiency benefits that are anticipated to arise as a result of the Amendment are consistent with the purpose of the Act that speaks to promoting economic efficiency in the generation, transmission, distribution and sale of electricity. The Amendment also supports the purposes that relate to encouraging electricity conservation, demand management and demand response; ensuring the adequacy, safety, sustainability and reliability of electricity supply in Ontario; and protecting the interests of consumers in relation to the adequacy and reliability of electricity service. While the Board acknowledges that the Amendment may result in an increase in average consumer bills, that increase is anticipated to be modest.

The Board is also of the view that, in the context of its mandate under section 33 of the Act, unjust discrimination means unjust economic discrimination.

Based on the record of this proceeding, the Board finds that the Amendment is consistent with the purposes of the Act. The Board also finds that the Amendment does not unjustly discriminate for or against a market participant or a class of market participants.

Other Matters

1. *Stay of the Amendment Pending Appeal*

By the terms of the Board's February 9, 2007 Order, the stay of the operation of the Amendment applies pending completion of the Board's review of the Amendment. Issuance of this Decision and Order completes the Board's review, and has by the terms of the Order the effect of lifting the stay. For greater certainty, however, the Board will include an order to that effect in this Decision and Order.

In its final written argument, AMPCO requested that, in the event that the Board does not revoke the Amendment, the Board order a stay of the Amendment pursuant to section 33(6) of the *Ontario Energy Board Act, 1998* pending appeal to the Divisional Court.

In the letter accompanying its final written argument, the IESO noted that this request for relief was not included in the Application and is out of time. While the IESO therefore did not address this request in its final written argument, the IESO did in its

letter express the view that the Board does not have jurisdiction to grant such relief, and that if AMPCO wants a stay it must apply to the Divisional Court. APPrO's position is to the same effect.

In the circumstances of this case, the Board has decided not to extend its February 9, 2007 order staying the operation of the Amendment.

The Board understands that the IESO may wish to proceed with implementation of the Amendment on a timely basis, and that parties that are supportive of the Amendment would be equally supportive of prompt implementation. However, the Board does not believe that it is in the best interests of the wholesale electricity marketplace to face the prospect of the Amendment being implemented one day and suspended shortly thereafter further to the invocation of a judicial process. The Amendment is not urgently required for reasons such as reliability and the ramp rate issue is one that has been outstanding for several years. In the circumstances, the Board expects that the IESO will act responsibly by allowing AMPCO a reasonable opportunity to request judicial recourse prior to taking whatever steps may be required to implement the Amendment. The Board similarly expects that AMPCO will act responsibly by ensuring that any request for a stay of the operation of the Amendment that it may wish to make to the Divisional Court is made without undue delay.

2. *New Obligations for IESO under its Licence*

In its final written argument, AMPCO requested that the Board require the following, either under an existing condition of the IESO's licence or by way of a new licence condition:

- that the IESO prepare and submit to the Board, for every proposed market rule and market rule amendment, a report supported by appropriate analysis and available to the public, that explains how the proposed rule or amendment is consistent with the objects of the IESO and promotes the purposes of the Act; and

- that, in relation to the Amendment and such other market rules or market rule amendments as the Board considers appropriate, the IESO report publicly on an annual basis with respect to whether and the extent to which the amendments have met the IESO's objectives and provided the benefits anticipated by the IESO at the time each of the amendments were made.

In the letter accompanying its final written argument, the IESO noted that this request for relief was not included in the Application, is out of time, was not dealt with in any way in this proceeding and is entirely inappropriate.

Whatever the Board may think of AMPCO's request on the merits, the Board does not consider it appropriate to address the request at this stage in the proceeding. The issue of new reporting requirements for the IESO in relation to amendments to the market rules was not raised by AMPCO on a timely basis, and the other parties to this proceeding will not have had a fair opportunity to consider and respond to the request. AMPCO may, if it so wishes, pursue this matter further outside the context of this proceeding.

3. *Cost Awards*

Parties eligible for an award of costs, as identified in Procedural Order No. 2, shall submit their cost claims by April 24, 2007. A copy of the cost claim must be filed with the Board and one copy is to be served on the IESO. The cost claims must comply with section 10 of the Board's *Practice Direction on Cost Awards*.

The IESO will have until May 8, 2007 to object to any aspect of the costs claimed. A copy of the objection must be filed with the Board and one copy must be served on the party against whose claim the objection is being made.

A party whose cost claim was objected to will have until May 15, 2007 to make a reply submission as to why its cost claim should be allowed. Again, a copy of the submission must be filed with the Board and one copy is to be served on the IESO.

The Board will issue its decision on cost awards at a later date once the above process has been completed.

THE BOARD ORDERS THAT:

1. The Application by the Association of Major Power Consumers in Ontario for an order under section 33(9) of the *Electricity Act, 1998* revoking the market rule amendment identified as MR-00331-R00: "Specify the Facility Ramping Capability in the Market Schedule" and referring the amendment back to the IESO for further consideration is denied.

2. The stay of the operation of the market rule amendment identified as MR-00331-R00: “Specify the Facility Ramping Capability in the Market Schedule”, as ordered by the Order of the Board dated February 9, 2007, is lifted.

DATED at Toronto, April 10, 2007.

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

APPENDIX A

to

Decision and Order
April 10, 2007

Association of Major Power Consumers in Ontario
Review of Market Rule Amendment
EB-2007-0040

Excerpt from Transcript of Oral Hearing Held March 29, 2007

(see attached document)

our binder. I apologize, it might just be me, but the record, the decision does not bear out the quote that that included.

MR. RUPERT: Mr. Rodger, I was going to mention, I think the page 5 reference, at least as I read it here, didn't refer to the page that was doing what you thought it did. Maybe there is a cross-reference issue in your submissions.

MR. RODGER: I'll certainly check that. Sorry, Mr. Rupert.

MR. KAISER: Why don't you have a look now, and see if you can help us.

MR. RODGER: Mr. Chair, we'll endeavour to get copies during the lunch break.

MR. KAISER: All right. We'll take the lunch break now. We'll come back at 2 o'clock.

--- Recess taken at 12:34 p.m.

--- On resuming at 2:11 p.m.

DECISION:

MR. KAISER: Please be seated.

The Board has decided to issue a decision now on the matter of the relevance of the evidence with respect to the process, rather than deferring it, as Mr. Rodger suggested, in order that we can proceed with the case in a more orderly manner.

We are dealing with an application by AMPCO under section 33(4) of the *Electricity Act* for review of the three times ramp rate market rule amendment. In that

context there has been a discussion and a concern about the scope of the case, and particularly whether evidence regarding the process by which the IESO reached this rule is relevant.

AMPCO submits that the three times ramp rate market rule amendment should be revoked by this Board and referred back to the IESO for stakeholder consultation, based on the following grounds: First, that the process followed by the IESO in the three times ramp rate stakeholder consultation process violated IESO's common-law duty of procedural fairness, by breaching AMPCO's legitimate expectation that the IESO would follow its published stakeholder engagement process and apply its stakeholder engagement principles, and raising a reasonable apprehension of bias that the IESO favoured the interests of generators; secondly, that the integrity of the statutorily-mandated consultation process has been undermined. They say this is inconsistent with the purposes of the *Electricity Act* and unjustly discriminates against Ontario consumers in favour of Ontario generators.

They also allege certain substantive failures, as well, which are not at issue in the proceeding this morning.

Accordingly, AMPCO argues that the materials produced by IESO relating to procedural matters are relevant both to the issue of procedural fairness and also the substantive issues.

The starting point in this discussion is section 33(9)

of the *Electricity Act*. It has been referred to by virtually everyone this morning. It provides that:

> "If, on completion of its review, the Board finds that the amendment is inconsistent with the purposes of this *Act*, or unjustly discriminates against or in favour of a market participant or a class of market participants, then the Board shall make an order revoking the amendment on the date specified by the Board and referring the amendment back to the IESO for further consideration."

AMPCO argues that all of the IESO materials are relevant because they demonstrate that the IESO failed to follow procedural fairness in developing the amendment. According to AMPCO, the lack of procedural fairness demonstrates that the amendment unjustly discriminates against its members in favour of generators.

In other words, AMPCO argues that it has rights of natural justice in IESO rule-making and that those rights should be enforced by the Board in the market review amendment process.

All of the other parties appearing before us this morning state that this is an incorrect interpretation of section 33(9), because it equates the term "unjustly discriminates" with a violation of the rules of natural justice and it equates the Board's review process with a judicial review application.

They argue that the purpose of the Board's review in a

market review amendment should be aimed at economic efficiency and not natural justice.

They say that the OEB should be reviewing an amendment to the IESO rules and not the IESO stakeholdering process; that the scope of the Board's review should be aimed at the rule itself, and the impact of that rule, not the process by which the amendment was made.

In other words, it's argued before us that the issue is whether the rule is unjustly discriminatory. The Board agrees with that position.

Sections 19(1) and 20 of the *OEB Act*, read together, provide that the Board has general authority to determine any question of law or fact arising in any matter before it except where that authority is limited by statutory provision to the contrary.

In the case of a market rule amendment, another statutory provision does limit the Board's jurisdiction. Section 33(9) of the *Electricity Act* specifically sets out certain grounds on which the Board may make an order.

Accordingly, we find that section 33(9) of the *Electricity Act* is a jurisdiction-limiting provision, not another jurisdiction-granting provision. That is, with respect to a market rule amendment, the Board's jurisdiction is not as broad as suggested by section 20 of the *OEB Act*, but limited by section 33(9) of the *Electricity Act*.

In this regard, the Board has also considered the submissions of various parties, and agrees, that the 60-day

time limit for disposing of this review is consistent with the conclusion that the Board's scope of review is limited to the criteria set out in section 33(9).

The legislature can be taken as having known that an exhaustive review of the process would render it impossible to meet these timelines.

We then come to what can be seen as a second and distinct issue. That is whether there is a common-law principle of administrative law that the IESO has violated in the course of this market rule amendment process which yields a separate and distinct remedy.

The IESO says the common-law principles of administrative law do not assist AMPCO in extending the jurisdiction of the Board to review the details of the stakeholdering process. They say that the IESO is a statutory corporation whose affairs are managed and supervised by an independent board of directors, and the functions carried out by the IESO under the review at issue in this proceeding is a rule-making function and is essentially a legislative function.

They rely upon the Supreme Court of Canada's 1980 decision in the Inuit Tapirisat as support for the proposition that in legislative functions these rules do not apply.

AMPCO takes a different view and it relies upon the Supreme Court of Canada 1990 decision in Baker, as well as the Divisional Court decision in Bezaire.

The aspects of the decision that AMPCO relies upon can

be found at pages 15 and 14, where the Court stated that one of the criteria that must be looked at in determining whether the rules of natural justice apply to a process is whether the parties had a legitimate expectation that those rules would be followed. The Court states, in part:

> "Fourth, the legitimate expectations of the person challenging the decision may also determine what procedures the duty of fairness requires in given circumstance."

They go on to say:

> "This doctrine as applied in Canada is based on the principle that the circumstances affecting procedural fairness take into account the promises or regular practices of administrative decision-makers and it would generally be unfair for them to act in contravention of representations as to procedure or to backtrack on substantive promises without according significant procedural rights."

The Court also noted that another factor to be considered in determining the nature and extent of the duty of fairness that's owed to the parties is the importance of the decision to individuals involved.

As has been pointed out, there's no question that there's a significant amount of money involved in this decision; it's an important decision. With respect to the expectations of the parties, there is a provision in section 13.2 of the *Electricity Act* requiring the IESO to

establish processes by which consumers, distributors and generators may provide advice. AMPCO makes the point that a framework was established to govern the process by which these rules would be amended and implemented. They say that this procedure, despite the expectation they were entitled to, has not been followed.

That may or may not be the case, but this Panel is of the view that that is not a matter for our consideration. Mr. Vegh in his submissions questioned whether the Board should be a parallel Divisional Court. We don't think it should be.

IESO may or may not have followed the rules of natural justice. And they may or may not have been required to do so based upon the different authorities that have been cited by the different parties. But that, we believe, is a matter to be determined by the Divisional Court, not the Ontario Energy Board.

Mr. Rodger did refer us to a decision of this Board on September 20th, 2005. That appears at tab 11 of Ms. DeMarco's brief. I'm reading in part:

> ”The Board concludes that stakeholder concerns have been substantially met. The true test will, however, be the experience of stakeholders in the new process. Stakeholders and the Board will have opportunities to review how well the process works over time as they are implemented. The Board therefore approves the IESO proposals on its stakeholdering process. It should be noted,

however, that this approval relates to the processes that the IESO has proposed. It does not change the Board's obligation to review IESO programs that have implications for IESO fees, expenses and revenue requirements, even when these programs have been subjected to the IESO stakeholdering process."

Mr. Rodger's submission was that having approved the stakeholdering process it was incumbent upon the Board to follow through and police, if you will, the rule-making process.

We differ on that. The two are distinct functions. The review at question is a judicial review and best reserved for the courts.

That leads us to the Order requested. Pursuant to this decision, the Board will order that any evidence relating to the stakeholdering process be struck. That would include Mr. Rodger's submission of March 26th. If the parties are unable to agree on what evidence is to be excluded or not excluded, the Board may be spoken to.

That completes the Board's ruling in this matter.

PROCEDURAL MATTERS:

Mr. Rodger and Mr. Mark, we were going to suggest, subject to your convenience, that you may want to adjourn for the rest of the day and regroup in light of that.

MR. MARK: It probably makes sense.

MR. KAISER: Unless there be some debate and discussion as to what evidence is to be struck and what

Ontario Energy Board

Commission de l'Énergie de l'Ontario

EB-2011-0013
EB-2011-0014
EB-2011-0015

IN THE MATTER OF the *Ontario Energy Board Act, 1998,* S.O. 1998, c.15, Schedule B; and in particular sections 36.1(1), 38(1), 40(1), 90(1), thereof;

AND IN THE MATTER OF an application by Union Gas Limited for an Order designating the area known as the Jacob Pool, in the Municipality of Chatham-Kent, as a gas storage area;

AND IN THE MATTER OF an application by Union Gas Limited for authority to inject gas into, store gas in and remove gas from the areas designated as the Jacob Pool and to enter into and upon the lands in the said areas and use the said lands for such purposes;

AND IN THE MATTER OF an application by Union Gas Limited to the Ministry of Natural Resources for a license to drill wells in the said areas;

AND IN THE MATTER OF an application by Union Gas Limited for an Order granting leave to construct natural gas pipelines in the Municipality of Chatham-Kent.

Before: Marika Hare,
Presiding Member

CORRECTED

DECISION ON MOTION TO STRIKE EVIDENCE AND PROCEDURAL ORDER NO. 3

Applications to Develop Jacob Pool

Union Gas Limited (“Union” or the “Applicant”) filed applications dated January 17, 2011, with the Ontario Energy Board (the “Board’) under sections 36.1(1), 38(1), 40(1) and 90(1) of the Ontario Energy Board Act, 1998, S.O. 1998, c.15, Schedule B (the “Act“) requesting an Order authorizing Union to develop and operate a natural gas storage area on lands located in the geographic area of the Municipality of Chatham-Kent referred to as the Jacob Pool.

A single Notice of Application was issued on March 7, 2011 and given file numbers EB 2011/0013/0014/0015. The Applicant served and published the Notice of Application as directed by the Board. The registered intervenors in this proceeding are: Invenergy Canada, Ministry of Natural Resources (“MNR”), Enbridge Gas Distribution Inc. (“Enbridge”) and the Kent Federation of Agriculture (“KFA”).

On March 29, 2011 the Board issued Procedural Order No. 1 which set the schedule for a written proceeding including a provision for intervenors to file evidence. The Board ordered that "the scope of this proceeding will be limited to the Issues List" attached to Procedural Order No. 1.

On April 11, 2011 the KFA filed intervenor evidence which, it submitted, was appropriately within the umbrella of Issue 1.3 of the Board’s Issues List. Issue 1.3 sets out the following: "Does the applicant have the necessary leases and agreements with the directly affected landowners?"

Accompanying the proposed evidence, KFA filed a letter to the Board dated April 11, 2011 wherein it stated that some leases submitted by the Applicant, as part of its prefiled evidence, contain clauses which indicate minimum annual payments equal to Lambton County Storage Association agreement payments and others appear to be industry “standard” leases, unamended. KFA noted that it “is concerned that compensation paid by Ontario storage operators is inadequate and unfair in today’s marketplace.”

Union’s Motion to Strike KFA Evidence

On April 14, 2011 Union filed a Notice of Motion regarding the KFA proposed evidence (the “Motion”). The Motion asked for an order of the Board striking the

KFA evidence from this proceeding on the grounds that the KFA evidence “is not relevant to the issues in this proceeding”.

On April 19, 2011 the Board issued Procedural Order No. 2 which set the schedule for submissions and reply submissions from the parties with respect to the Motion and the issue of whether the KFA evidence should be struck from the record in this proceeding.

Submissions on the Motion

The KFA, Board Staff and Union filed submissions on Union’s Motion.

By way of letter dated April 20, 2011 KFA stated, among other things, that: “KFA has no objection to the Board making an Order striking the evidence filed by KFA on April 11th, 2011 from these proceedings, without prejudice to:

> (a) KFA’s right to re-submit its evidence with respect to the issue of compensation in these proceedings; and
>
> (b) KFA’s right to move the Board pursuant to section 21(1) of the Ontario Energy Board Act (“OEBA”) to order a hearing to determine what constitutes just and equitable compensation pursuant to section 38 (2).”

On April 26, 2011, Board staff filed submissions in support of Union’s Motion that the Board make an Order striking the evidence filed by KFA.
Board staff stated that its support of Union’s motion is based on the legal interpretation of section 38(3) of the Act which was also cited by Union in its Motion, and on the fact that the KFA consented to the Motion to strike its evidence from the record of the proceeding.

Board staff submitted that, consistent with previous Board decisions[1], an owner of storage rights who has a valid agreement with a prospective storage operator or current storage operator, is not eligible to obtain an order of the Board regarding compensation for the storage rights which are covered by the agreement.

[1] RP 1999-0047, Union Gas Limited and Ontario Energy Board, Decision with Reasons

Board staff also stated that in this case the landowners referred to in the additional evidence filed by the KFA all have valid agreements with Union. Board staff argued that regardless if the individual landowners have agreements, the KFA, is not a landowner within the proposed Jacob Pool, and as such has no standing to file the evidence and bring its motion with respect to the issue of compensation.

Union filed its Reply submission on April 27, 2011. Union disagreed with the statement made by KFA that it has a "right to re-submit its evidence with respect to the issue of compensation in these proceedings". Union stated that "If, in the future, a *landowner* commences an application under s. 38(3) of the *OEB Act, 1998,* then a landowner (or its representative) may file evidence, and the Board may determine who else may file evidence and on what issues in the normal course."

Board Findings on the Motion

The Board grants Union's Motion for an order striking the evidence filed by the KFA on April 11, 2011.

As set out by both Union and Board staff in their respective submissions, the KFA is not a landowner and as such cannot be deemed to have direct interest in compensation matters that arise from operation of a designated gas storage pool. Section 38 of the Act provides:

> **Authority to store**
>
> 38. (1) The Board by order may authorize a person to inject gas into, store gas in and remove gas from a designated gas storage area, and to enter into and upon the land in the area and use the land for that purpose.
>
> **Right to compensation**
>
> (2) Subject to any agreement with respect thereto, the person authorized by an order under subsection (1),
>
> (a) shall make to the owners of any gas or oil rights or of any right to store gas in the area just and equitable compensation in respect of the gas or oil rights or the right to store gas; and

(b) shall make to the owner of any land in the area just and equitable compensation for any damage necessarily resulting from the exercise of the authority given by the order.

Determination of amount of compensation

(3) No action or other proceeding lies in respect of compensation payable under this section and, failing agreement, the amount shall be determined by the Board.

In accordance with the Act, only landowners can seek a determination from the Board for appropriate compensation. As such, only individual landowners within the Jacob pool, or any other gas storage pool in Ontario, may file an application for a right to compensation under section 38(3) of the Act as long as they can demonstrate that there is no agreement with a gas storage operator. The Board therefore grants Union's Motion striking the evidence filed by KFA. With respect to KFA's request that the Board confirm its right to resubmit evidence with respect to compensation in these proceedings, the Board confirms its position noted above: only individual landowners within the Jacob pool may file an application for a right to compensation. As such, a landowner may file evidence in that proceeding and the Board can make any determinations in that proceeding about further evidence being filed.

KFA also requested that the Board confirm its "right to move the Board pursuant to Section 21 (1)" of the Act. The Board notes that the section of the Act provides as follows:

21. (1) The Board may at any time on its own motion and without a hearing give directions or require the preparation of evidence incidental to the exercise of the powers conferred upon the Board by this or any other Act.

As such, the Board confirms that it is not up to a party to make a motion to the Board to hold a hearing. As noted by Union in its reply submission, there is no right for a person to bring a motion for an order commencing a proceeding.

The Motion filed by Union is granted in its entirety. As such, the Board finds it necessary to establish a new procedural schedule as part of this procedural order. Parties are to take note that the schedule set out herein replaces the

schedule set out in Procedural Order No. 2.

The Board considers it necessary to make provision for the following procedural matters. The Board may issue further procedural orders from time to time.

THE BOARD ORDERS THAT:

1. The intervenor evidence filed by Kent Federation of Agriculture on April 11th, 2011 is struck from the record of the EB-2011-0013/0014/0015 proceeding.

2. Written interrogatories on the Applicant's pre-filed evidence shall be filed with the Board and copies delivered to the Applicant and all intervenors on or before **Monday, May 16, 2011.** All interrogatories must reference the specific evidence on which the interrogatory is based and indicate the issue number according to the Issues List provided in the Appendix B to Procedural Order No. 1.

3. Responses to the interrogatories shall be filed with the Board and delivered to the Applicant and all intervenors on or before **Wednesday, May 25, 2011**.

4. A Technical Conference will be convened on **Thursday, June 2, 2011** at 9:30 a.m. The Technical Conference will be held at 2300 Yonge Street, Toronto in the Board's West Hearing Room on the 25th Floor.

5. Intervenors and Board staff shall file their submissions, if any, and deliver copies to Union and all other parties on or before **Friday, June 10, 2011.**

6. Union shall file its reply argument, if any, and deliver copies to Board staff and intervenors on or before **Friday, June 17, 2011.**

All filings to the Board must quote file numbers EB-2011-0013; EB-2011-0014; and EB-2011-0015, be made through the Board's web portal at www.errr.ontarioenergyboard.ca, and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address.

Please use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.ontarioenergyboard.ca. If the web portal is not available you may email your document to the BoardSec@ontarioenergyboard.ca. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Those who do not have computer access are required to file seven paper copies. If you have submitted through the Board's web portal an e-mail is not required.

All communications should be directed to the attention of the Board Secretary at the address below, and be received no later than 4:45 p.m. on the required date.

DATED at Toronto May 05, 2011
ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

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RP-1999-0047

2
IN THE MATTER OF the Ontario Energy Board Act, 1998[12JF7-1:1], S.O. 1998, C.15, Schedule B;

3
AND IN THE MATTER OF an Application by Union Gas Limited for a regulation designating the area known as the Mandaumin Pool in the Townships of Enniskillen and Plympton, and the City of Sarnia, Lambton County as a gas storage area; and for authorization to inject gas into, store gas in, and remove gas from the said Pool;

4
AND IN THE MATTER OF an Application by Union Gas Limited for a regulation designating the area known as the Bluewater Pool in the Township of Moore and the City of Sarnia, Lambton County as a gas storage area; and for authorization to inject gas into, store gas in, and remove gas from the said Pool;

5
AND IN THE MATTER OF an Application by Union Gas Limited for a regulation designating the area known as the Oil City Pool in the Township of Enniskillen, Lambton County as a gas storage area; and for authorization to inject gas into, store gas in, and remove gas from the said Pool;

6
AND IN THE MATTER OF an Application by Union Gas Limited for an order granting leave to construct natural gas pipelines in the Townships of Enniskillen, Plympton, Moore and Dawn-Euphemia, and the City of Sarnia;

7
AND IN THE MATTER OF an Application by Union Gas Limited to the Minister of Natural Resources for licences to drill or deepen 7 wells in the proposed designated storage areas;

Was preliminary page 2 8
AND IN THE MATTER OF an Application by Union Gas Limited for approval of the parties to, the period of, and the storage that is the subject of proposed storage contracts.

9
Before: Sheila K. Halladay
Presiding Member
J. B. Simon

Member
F. A. Drozd
Member

10

REPORT OF THE BOARD TO THE LIEUTENANT GOVERNOR IN COUNCIL REPORT TO THE MINISTER OF NATURAL RESOURCES DECISIONS WITH REASONS

11

March 30, 2000

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APPENDICES

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1. THE APPLICATIONS AND HEARING

17

1.1 The Applications

18

1.1.1 Union Gas Limited ("Union" or the "Applicant" or the "Company") filed the following applications, each dated September 27, 1999, with the Ontario Energy Board (the "Board") pursuant to the Ontario Energy Board Act, 1998 (the "Act"):

19

- under subsection 127(2)[12JF7-1:1196] of the Act for a regulation under clause127(1)(e)[12JF7-1:1187] of the Act designating the area containing a gas reservoir located in Lot 1 and part of Lot 2, Concession XIV, Enniskillen Township; Lot 1 and part of Lot 2, Concession I, Plympton Township; and Lot 1 and part of Lot 2, Concession II, part of Lots 1 and 2, Concession III, and the public road allowances of roads known as Churchill Line and Mandaumin Road, City of Sarnia, all in the County of Lambton, shown in Figure 1[383], as a gas storage area (the "Mandaumin Pool");

20

- under subsection 127(2) of the Act for a regulation under clause 127(1)(e) of the Act designating the area containing a gas reservoir located in part of Lots 2, 3 and 4, Concession I, Moore Township (geographic township of Sarnia); and part of Lots 2,3, and 4, Concession II, City of Sarnia; and part of the public road allowance known as Waterworks Road, City of Sarnia and Township of Moore, shown in Figure 2[385], as a gas storage area (the "Bluewater Pool");

21

- under subsection 127(2) of the Act for a regulation under clause 127(1)(e) of the Act designating the area containing a gas reservoir located in part of Lots 16 and 17, Concessions IV and V, Enniskillen Township; and part of the road allowance of Rose, Shamrock and Main Streets, and part of the public road allowance known as Courtright Line (formerly King's Highway No 80), Enniskillen Township, all in the County of Lambton, as shown in Figure 3[387], as a gas storage area (the "Oil City Pool");

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- under subsection 38(1)[12JF7-1:293] of the Act for authorization to inject gas into, store gas in, and remove gas from the Mandaumin Pool if designated as a gas storage area , the Bluewater Pool if designated as a gas storage area and the Oil City Pool if designated as a gas storage area, and to enter into and upon these lands and use these lands for such purpose;

23

- under section 40(1)[12JF7-1:312] of the Act for a favourable report from the Board to the Minister of Natural Resources ("MNR") to which the Applicant has applied for licences to drill or deepen five (5) injection/withdrawal wells and two (2) observation wells within the proposed designated storage areas of the Mandaumin Pool, the Bluewater Pool and the Oil City Pool;

24 • under subsection 90(1)[12JF7-1:886] of the Act for an order or orders granting leave to construct approximately 3 kilometres of NPS 12, NPS 10, NPS 8 and NPS 4 storage gathering pipelines in the proposed designated storage areas of the Mandaumin Pool, the Bluewater Pool, and the Oil City Pool (collectively, the "gathering lines");

25 • under subsection 90(1) of the Act for an order or orders granting leave to construct approximately 22 kilometres of NPS 16, 1.3 kilometres of NPS 12 and 9.7 kilometres of NPS 10 transmission pipelines (the "transmission pipelines") together with measurement and flow control facilities; and

26 • under subsection 39(2)[12JF7-1:306] of the Act for approval of the parties to, the period of, and the storage that is the subject of proposed gas storage contracts to be served by the development of the Mandaumin Pool, the Bluewater Pool and the Oil City Pool.

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1.2 The Hearing

28 1.2.1 The Board issued its Notice of Application on October 6, 1999.

29 1.2.2 The Board issued Procedural Order Number 1 on November 9, 1999 setting out dates for filing interrogatories, supplementary interrogatories, responses and intervenor evidence, and the date for a technical/issues conference.

30 1.2.3 A Technical Conference was held at the Board's offices on December 16, 17 and 21, 1999. Representatives of the Applicant, the Lambton County Storage Association ("LCSA"), CanEnerco Limited ("CanEnerco"), Enbridge Consumer Gas, the Township of Dawn-Euphemia, and Board staff attended the Technical Conference. Mr Stan Klapak appeared on his own behalf.

31 1.2.4 The Board issued Procedural Order Number 2 on January 5, 2000 setting out the issues list, approved by the Board, and setting the date for the oral hearing.

32 1.2.5 On January 11, 2000, Union filed a motion with the Board to strike out the prefiled evidence of Dr. Walter W. Haessel and Robert J. Hunt, each filed on behalf of the LCSA.

33 1.2.6 On January 28, 2000 the LCSA filed an application with the Board under subsection 38(3)[12JF7-1:299] of the Act on behalf of all LCSA landowners within Union's existing integrated storage system for fair and equitable compensation (the "LCSA Section 38 Application").

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1.2.7 On January 28, 2000, the LCSA filed a cross-motion requiring the Board: to hear and determine the issue of fair and equitable compensation under subsection 38(3) of the Act for the landowners who owned property within the proposed designated storage areas at the hearing of this proceeding; or to adjourn the compensation issue in this proceeding to be heard together or consecutively

with the LCSA Section 38 Application; or to stay this proceeding, pending the disposition of the LCSA 38 Application.

35

1.2.8 The Motion and the Cross-Motion were heard at the Board's offices on February 2, 2000. The Board ordered that, for the purposes of this proceeding, the prefiled evidence of Robert J. Hunt be struck. The Board also struck the evidence of Dr. Walter Haessel, except for matters relating to the technical issues of cushion gas and the boundaries of the designated storage area. The Board ordered that the issue of the amount of compensation to be paid to landowners affected by this proceeding be dealt with together with the LCSA Section 38 Application for fair and equitable compensation for all LCSA landowners within Union's territory.

36

1.2.9 The hearing of the Applications took place at the Holiday Inn, 1498 Venetian Boulevard, Sarnia, Ontario on February 8 and 9 and 10, 2000. An oral summary of the issues was presented by Board staff and the Applicant presented oral reply argument on February 10, 2000.

37

1.2.10 Representatives of the following parties appeared at the hearing:

38

Glenn Leslie	Union Gas Limited
	Lambton County Storage Association
Paul G. Vogel	
Robyn Marttila	
	CanEnerco Limited
Philip Walsh	
Joe Gorman	
Barry R. Card	Township of Dawn-Euphemia
Jennifer Lea	Board Counsel

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1.2.11 The Applicant called the following Company witnesses:

40

Lynn M. Galbraith	Group Manager, Storage & Transportation, Sales & Services
Laura F. Callingham	Team Leader, Financial Analysis
Gerald D. Mallette	Manager, Pipeline Projects
Joseph A. Marusic	Chief Storage Planning Engineer
James G. Egden	Chief Geologist
Steven R. Pardy	Senior Reservoir and Drilling Engineer
David R. Lowe	Storage Business Manager
Byron L. Haley	Senior Lands Agent, Lands Department
William T. Wachsmuth	Co-ordinator, Project Asset Development
Gregory A. Payne	Environmental Planner, Pipeline Engineering

41

1.2.12 The Applicant also called the following witnesses:

2012 ONSC 2708
Ontario Superior Court of Justice (Divisional Court)

Kawartha Lakes (City) v. Ontario (Director, Ministry of the Environment)

2012 CarswellOnt 6579, 2012 ONSC 2708, 215 A.C.W.S. (3d)
125, 293 O.A.C. 149, 349 D.L.R. (4th) 496, 67 C.E.L.R. (3d) 123

The Corporation of the City of Kawartha Lakes, Appellant and Director, Ministry of the Environment, Wayne Gendron, Liana Gendron, Doug Thompson Fuels Ltd., D.L. Services Inc., Farmers' Mutual Insurance Company and Ian Pepper Insurance Adjusters Inc., Respondents

W.L. Whalen, H. Sachs, T. Herman JJ.

Heard: April 26, 2012
Judgment: May 28, 2012
Docket: Toronto 421/10

Proceedings: affirming *Kawartha Lakes (City) v. Ontario (Director, Ministry of the Environment)* (2010), 52 C.E.L.R. (3d) 273, 2010 CarswellOnt 5518 (Ont. Environmental Review Trib.)

Counsel: Christine G. Carter, for Appellant
Nadine Harris, Frederika Rotter, for Respondent Director, Ministry of the Environment
Martin P. Forget, for Respondents, Wayne and Liana Gendron

***H. Sachs J.*:**

1 Several hundred litres of furnace oil leaked from the basement of privately owned property located in the City of Kawartha Lakes (the "City.") The oil seeped onto property that the City owned and from there had the potential to adversely affect Sturgeon Lake. The Ministry of the Environment (the "MOE") ordered the private property owners to remediate the damage. The owners, who had limited financial resources, made an insurance claim, but their insurance funds ran out before remediation could be completed on the City property. The MOE then ordered the City to clean up the contamination on its property and to prevent discharge of the contaminant from its property.

2 This is an appeal by the City from the decision of the Environmental Review Tribunal (the "Tribunal") upholding the MOE order, which was issued by the Director, Ministry of the Environment (the "Director") under the *Environmental Protection Act*, R.S.O. 1990, c. E.19 (the "Act.")

3 The appeal centres on the question of what are the appropriate considerations in making a clean-up order under the Act, against an owner of contaminated land who had no responsibility whatsoever for the contamination. According to the City, the Tribunal erred in law and breached the rules of natural justice when it refused to allow the City to call evidence directed at proving the City's innocence and determining who was actually at fault for the contamination. According to the Respondents, the Tribunal did not err when it found that in this situation its primary mandate, protecting the environment, would not be furthered by engaging in a fault-finding exercise. That exercise was more properly carried out in another forum.

4 For the reasons that follow I would dismiss the appeal.

Factual Background

Events Leading up to the Tribunal Proceedings

5 In December of 2008 several hundred litres of furnace oil leaked from the basement of Wayne and Liana Gendron's house located at 93 Hazel Street, in the City of Kawartha Lakes, Ontario. Thompson Fuels had pumped the fuel into the storage tanks at the Gendron home.

6 When Mr. Gendron noticed the leak he contacted his insurance company, who retained D.L. Services Inc. to begin remediation measures. D.L. Services commenced their work at the end of December. They noticed that the furnace oil had entered the City's municipal storm sewer system and culverts and was being discharged into Sturgeon Lake. They notified the MOE about what was occurring.

7 In response, a Provincial Officer attended at the site and, after observing the discharge of furnace oil into the environment, issued an order to Mr. Gendron requiring him to assess the extent of the spill, eliminate any adverse effects caused by the spill and restore the natural environment. That order was later amended to include Mr. Gendron's estranged wife.

8 In March of 2009 the MOE was notified that the Gendron's insurance coverage had reached its limit. This meant that any clean-up efforts beyond the Gendron's property would be discontinued since the Gendrons did not have the financial means to continue the work. By this time the Gendron property itself had been sufficiently remediated. However, contamination on the property owned by the City still had the potential to adversely impact Sturgeon Lake.

9 As a result, on March 27, 2009, the MOE issued a Provincial Order to the City, requiring the City to take all reasonable steps to prevent discharge of contaminant from its own property and to remediate its property. The City requested a review of this Order by the Director and the Director confirmed the Order (subject to certain timetable variations) on April 9, 2009.

Proceedings Before the Tribunal

10 On April 24, 2009, the City filed a Notice of Appeal with the Tribunal seeking to revoke the order that required it to remediate its property. At a preliminary hearing held in June of 2009, the Tribunal granted party status to the Gendrons, their insurer (Farmers Mutual Insurance Company), their adjuster (R. Ian Pepper Insurance Adjusters Inc.), the clean-up firm (D.L. Services Inc.), and the fuel provider (Thomson Fuels Ltd.)

11 On September 23 and 24, 2010, the Tribunal heard a motion brought by the Gendrons seeking to exclude any evidence that the City sought to call on the question of who was at fault for causing the spill and the reasonableness of any costs incurred in remediating the spill. On November 20, 2009, the Tribunal granted the motion and, as a result, the parties who had been added to the hearing in June of 2009 discontinued their participation in the City's appeal.

12 The Tribunal heard the City's appeal on April 27, 28 and 29, 2010. On July 16, 2010, the Tribunal issued a decision dismissing the appeal.

The Statutory Scheme

13 The purpose of the Act is described in section 3(1) as providing for "the protection and conservation of the natural environment."

14 Under s. 157.1(1), a provincial officer may issue an order "to any person who owns or who has management or control of an undertaking or property" requiring that person to take steps to "prevent or reduce the risk of a discharge of a contaminant into the natural environment from the undertaking or property" or "to prevent, decrease or eliminate an adverse effect that may result from" the discharge or presence of such a contaminant.

15 A person served with a s. 157.1 order may request the Director to review the order. The Director has the power to revoke, confirm or alter the order. A Director's Confirming Order may be appealed to the Tribunal under s. 140 of the Act. The Tribunal holds a hearing *de novo* and may confirm, alter or revoke the Director's Order.

16 Section 145.6(1) of the Act provides that a party to a hearing before the Tribunal may appeal the Tribunal's decision on a question of law to the Divisional Court.

17 Section 100.1 of the Act provides a municipality with a summary remedy to recover its costs for cleaning up a spill that it did not cause by issuing an order for payment to the owner of the pollutant or the person having control of the pollutant. In this case, after the Tribunal declined to revoke the Director's Confirming Order, the City issued s. 100.1 orders against the Gendrons, the fuel provider (Thompson Fuels Ltd.) and the Technical Standards and Safety Authority. The parties to whom the orders were directed appealed to the Tribunal, which had the effect of staying the City's s. 100.1 orders. These parties sought to adjourn the hearing of the appeal until such time as the civil proceedings that had been commenced by the City and others were resolved. The adjournment request was heard by the Tribunal and on March 15, 2011, the Tribunal adjourned the appeal "to give the parties an opportunity to try to reach a full resolution of the monies at issue in this proceeding (and any related issues) through negotiation, mediation or trial under the wider rubric of the Superior Court proceedings."

The Tribunal's Decisions

The Evidentiary Ruling

18 This ruling addressed whether the scope of the City's appeal from the Director's Confirming Order should be restricted so as to exclude any evidence and argument relating to the issue of whose fault it was that the spill contaminated City land and whether the costs incurred for remediating the spill were reasonable (given that the contamination could have been better contained by those at fault).

19 The request for the ruling arose from the fact that the City had circulated a draft statement of facts upon which it intended to rely at the appeal that made the following assertions:

> (a) Mr. Gendron failed to report the spill promptly as required.
>
> (b) If immediate action had been taken to remediate the spill then the spill could have been largely contained on the Gendron property and the costs associated with remediating the spill would have been well within the Gendrons' insurance limits.
>
> (c) When the decision was made to use the insurance proceeds to remediate Sturgeon Lake, which is under federal jurisdiction, prior to remediating the property that was owned by the City, this decision was one that preferred the interests of others over the interests of the taxpayers of the City.
>
> (d) The City, unlike others who were involved in dealing with the spill (including the MOE), had no opportunity to prevent the spill and to ensure that it was contained on private property.
>
> (e) Each of the homeowners, the furnace oil provider and/or the manufacturer of the fuel holding tank bore responsibility for causing the spill.
>
> (f) The City was in no way responsible for the spill or for failing in any efforts to contain the spill.

20 According to the Gendrons, who brought the motion to exclude evidence, these assertions spoke to matters that were irrelevant in the appeal before the Tribunal. Essentially, according to the Gendrons, the City was asserting that it was an innocent party that had not caused the spill and had had no opportunity to be involved in taking preventative measures to ensure that the spill did not come onto its property. Everyone agreed that the City was an innocent owner. The Gendrons argued that to require the Tribunal to hear evidence about why and who was the party at fault would serve to lengthen the hearing without adding anything of probative value to the matters that the Tribunal had to consider.

21 The City submitted that it was going to use the proposed evidence on the conduct of others to make its case on the issue of "fairness" as that word is used in *724597 Ontario Ltd., Re* (1994), 13 C.E.L.R. (N.S.) 257 (Ont. Environmental App. Bd.); aff'd. (1995), 26 O.R. (3d) 423 (Ont. Div. Ct.) ("*Appletex*.") In *Appletex*, two orderees who had some involvement in a

polluting enterprise were relieved from some aspects of a Director's order to remediate based on "fairness" factors. These factors included considerations as to whether the person to whom the order was directed had exercised due diligence to avoid creating the problem, whether the causes of the problem were within or outside the orderee's control and whether the orderee could have foreseen the risk or problem that had occurred.

22 The Tribunal granted the Gendron motion to exclude evidence. In doing so, it found that no one was disputing that the City was entirely an innocent owner — it had not caused the problem and was not in a position to control how the problem was initially remediated. Evidence further proving this was not required. At the hearing on the merits, the City was entitled to rely on its status as innocent owner to ground any of the arguments it wished to make about the fact that the Director's Confirming Order should be revoked.

23 The Tribunal also found that it was not the appropriate forum for making determinations as to who was at fault for the spill and to what extent. There were other forums that were more appropriate for this exercise, including the civil courts. The overriding purpose of the Act was clear: to protect the environment. In this case, delving into the circumstances giving rise to the contamination would undermine that purpose. As put by the Tribunal, "...it is difficult to know where such an inquiry would lead. Would it stop at the homeowner or go to the fuel supplier, the tank manufacturer, the parts manufacturer, etc.?" (Tribunal Decision, November 20, 2009, page 27.) In the meantime, there was a contamination that needed to be controlled and there was an orderee named who admitted that it fell within the class of persons who could be named in an order under the Act.

24 Finally, the Tribunal emphasized the changes that had occurred in the legal landscape during the fifteen years since *Appletex* had been decided.

25 Since *Appletex*, decisions (including *R. v. Consolidated Maybrun Mines Ltd.*, [1998] 1 S.C.R. 706 (S.C.C.)) have emphasized the fact that the purpose of the Act is not just to remedy environmental damage that has occurred, but to prevent further contamination from occurring. As put by the Supreme Court of Canada in *Maybrun*, "This purpose must, therefore, be borne in mind in interpreting the schemes and procedures established by the Act" (para. 54.)

26 The Tribunal that heard *Appletex* commented on the absence of legislative or policy guidance as to how provincial officers were to exercise their discretion under the Act. Since *Appletex*, the Ministry has filled that vacuum by publishing a Compliance Policy (the "Compliance Policy") the stated purpose of which is "to provide guidance to Ministry staff in exercising their authorities under statutes administered by the Ministry of the Environment" (Compliance Policy, May 2007, page i.)

27 The Compliance Policy makes it clear that if there are two or more persons who can be named in an order under s. 157.1, it is not up to the provincial officer issuing the order to apportion liability as amongst the various orderees. Each orderee is generally considered to be jointly and severally liable under the order and it is to be left to the parties to sort out the apportionment of liability amongst themselves.

28 The Compliance Policy also contains a specific provision dealing with "victimized" or innocent owners. According to that provision, current owners, innocent or not, should be named in an order. If there are exceptional and unusual circumstances, the timing and the content of the work to be done by a victimized owner can be adjusted. As well, if no environmental purpose would be served by naming the owner in the order, they do not need to be named.

29 In summary, according to the Tribunal, evidence that spoke to the fact that the City was not the polluter was not necessary since this was admitted. Evidence that sought to lay blame on others for the contamination was not, in this case, relevant to any issue that would have an effect on the appeal. Thus, the Tribunal ruled that, "The appeal will exclude evidence and argument regarding fault for causing the spill and the reasonableness of the costs that have been incurred in remediating the spill" (Tribunal Decision, November 20, 2009, page 34.)

The Tribunal's Decision on the Merits of the Appeal

30 After a three-day hearing, the Tribunal dismissed the City's appeal. During the hearing the Tribunal heard from four witnesses, two on behalf of the MOE and two who were called by the City. One City witness testified about an alleged agreement

that the MOE and the City had reached about not issuing an order when it did. Ultimately, the Tribunal did not accept the City's version of these events. The second City witness testified that the spill could have been contained on the Gendron property had it been dealt with promptly. If this had happened, the Gendron insurance proceeds would have covered the clean-up costs.

31 The main issue that was addressed on the appeal was whether the Director's Confirming Order was unfair, unreasonable and contrary to the "polluter pays" principle. Essentially, the City argued that as an innocent owner and as a victim of inaction on the part of others who could have prevented the spill from contaminating its land, it was unfair and unreasonable that it should have to pay the costs associated with remediating the contamination. Furthermore, it argued that one of the fundamental principles that should govern any order under the Act is the "polluter pays" principle. Since it was not the polluter and others were, it should not be paying.

32 The Tribunal found that the Act enshrined a system that specifically contemplated making innocent owners initially responsible for the clean-up and prevention of contamination, if to do so would promote the fundamental purpose of the Act: to protect the environment. Section 157.1 of the Act makes no mention of fault. Thus, to the extent that the City was arguing that this was unfair or unreasonable, its complaint was with the legislature which had, in enacting the Act, accepted that some unfairness to innocent owners was justifiable in order to protect the environment and to prevent the unfairness that could result to others from a compromised environment.

33 Furthermore, the Tribunal found that it was not sufficient for the City to ask the Tribunal to revoke a jurisdictionally and environmentally sound Order, without addressing how, if the Order were revoked, the environmental protection objective of the Act would be met. As put by the Tribunal:

> The reason for this is that the Tribunal is charged with carrying out its appellate mandate in the context of specific statutory purposes. It cannot ignore the environmental protection objective of the *EPA* and simply state that it would be fairer to the City that it be relieved from compliance. Fairness to the City must be accompanied by a solution that is also fair to the environment and fair to those affected by the pollution at issue here, including those who use Sturgeon Lake. (Reasons of the Tribunal, July 16, 2010, page 11.)

34 For these reasons the Tribunal dismissed the City's appeal and refused to revoke the Director's Confirming Order.

Issues Raised on This Appeal

35 The Appellant made two submissions on this appeal:

> (i) The Tribunal erred in law when it made its ruling on November 30, 2009 limiting the evidence that the City could call in support of its appeal. In particular, the City submitted that the evidence that was excluded spoke to the "fairness factors" that two prior Divisional Court decisions have held are appropriate for the Tribunal to consider when deciding whether it should make an order requiring someone to remediate environmental damage.
>
> (ii) The Tribunal breached the rules of natural justice when it refused to allow the Appellant to call the evidence it wished to call and then found that the Appellant had "not put forward an environmentally responsible solution in support of a revocation of the Director's Order."

36 The Gendrons argued, among other things, that the appeal should be dismissed on the ground that it was moot since the City had complied with the Director's Confirming Order and performed the remediation work required.

Should the Appeal be Dismissed as Moot?

37 We agree that this appeal is now moot, in the sense that the live controversy that existed between the parties has disappeared. What we must now decide is whether we should exercise our discretion to hear the appeal in spite of the fact that it is moot.

38 Generally, courts will refuse to hear matters that are moot. Our system of dispute resolution is structured as an adversarial one. If the controversy has ended, there may be no adversaries who are interested in providing the court with the material it needs

to properly make a decision. Furthermore, judicial resources are scarce and should generally be expended on live controversies, not on academic exercises. The courts must be conscious of their proper role (*Borowski v. Canada (Attorney General)*, [1989] 1 S.C.R. 342 (S.C.C.); *Mental Health Centre Penetanguishene v. R.*, 2010 ONCA 197 (Ont. C.A.).)

39 In this case, both the City and the MOE requested that we exercise our discretion to hear the appeal. According to them, the issue at stake is one that is important and could impact their future dealings with each other on environmental issues. Thus, it is in the public interest that the matter be addressed by the court.

40 Furthermore, they pointed out the City acted in the public interest in remediating the damage by complying with the Order before it had a chance to fully litigate its request that the Order be revoked. If the City had waited until this appeal was heard, the damage to Sturgeon Lake could have been much worse. Environmental contamination often requires quick remediation. To dismiss the appeal because the City acted in the public interest could discourage others from doing the same.

41 In *Mental Health Centre Penetanguishene*, *supra*, the Court of Appeal recognized that, "The mootness doctrine may also be shunted to the sidelines when the issues raised are of public importance and their resolution is in the public interest" (para. 42.)

42 In this case, it is our view that the resolution of the issues in this appeal is in the public interest. In addition, in spite of the fact that the live issue is resolved, the adversarial context persists. We have had the benefit of full argument on the issue from all interested parties. The circumstances giving rise to this appeal are likely to recur between the City (or other similarly-placed municipalities or entities) and MOE. Environmental contamination of municipally owned property through no fault of the municipality is a phenomenon that could repeat itself, giving rise to the questions at stake in this appeal. We do not wish resolution of these questions to come at the expense of environmental damage by insisting that if the City wishes to appeal a determination on the issue it has raised in this appeal, it should not comply with an order to remediate.

Standard of Review

43 Under the Act, appeals from the Tribunal lie to this court on a question of law. Given this, the Appellant submits that the appropriate standard of review for this court to apply to the Tribunal's decisions is correctness. According to the Appellant, the Tribunal committed an error of law when it excluded the evidence that the City wished to call, thereby failing to recognize that it was bound by *Appletex* and another decision of this Court, *Montague v. Ontario (Director, Ministry of the Environment)* (2005), 12 C.E.L.R. (3d) 271, 196 O.A.C. 173 (Ont. Div. Ct.), that also held that "fairness" was an appropriate consideration under s. 157.1 of the Act. In *Montague*, the Divisional Court applied a standard of correctness to the appeal.

44 The Respondents argue that the Tribunal, an expert tribunal, was dealing with a question of law involving its home statute and its decision, which was an evidentiary ruling, is owed deference by this Court and should be reviewed on a standard of reasonableness.

45 *Montague* was decided before the Supreme Court of Canada released its decision in *New Brunswick (Board of Management) v. Dunsmuir*, 2008 SCC 9, [2008] 1 S.C.R. 190 (S.C.C.). In *Montague* the Divisional Court looked at four factors to determine the proper standard of review: the presence or absence of a privative clause or statutory right of appeal; the expertise of the tribunal relative to that of the reviewing court on the question in issue; the purpose of the legislation; and the nature of the question — law, fact or mixed fact and law.

46 The Court in *Montague* pointed out that the Act does provide for a statutory right of appeal on questions of law and since the appeal before it involved a question of law, this favoured "the normal appellate standard of correctness" (*Montague* at para. 12.) With respect to the expertise of the Tribunal, the Court found that the members of the Tribunal did not require any legal or scientific experience or training and therefore a consideration of this factor also pointed to a review standard of correctness. In the Court's view, the purpose of the legislation, which requires the Tribunal to balance multiple interests, including policy objectives, favoured a more deferential standard. It also found that the question before it was whether the Director had the jurisdiction to make the s. 157.1 order he had made in that case. This was a question of law of general importance that should be reviewed on a correctness standard. Weighing all of these considerations, the Court in *Montague* concluded that the correct standard of review was correctness.

47 In *Dunsmuir*, which was decided after *Montague*, courts were given new direction about how they should determine what standard of review to apply to the decision of an administrative tribunal. The Supreme Court directed that a consideration of the following factors would "lead to the conclusion that the decision-maker should be given deference and a reasonableness test applied": the existence of a privative clause; a tribunal with specialized expertise; and a question of law that does not rise to the level of (i) a question of central importance to the legal system as a whole and (ii) a question that is outside the specialized area of expertise of the tribunal (para. 55).

48 *Dunsmuir* also states that, "Where the question is one of fact, discretion or policy, deference will usually apply automatically" and that "the same standard must apply to the review of questions where the legal and factual issues are intertwined with and cannot be readily separated" (para. 53.) In addition, "Deference will usually result where the tribunal is interpreting its own statute or statutes closely connected to its function, with which it will have particular familiarity" (para. 54.) Furthermore, while true questions of jurisdiction may attract a standard of correctness, "jurisdiction" is to be construed narrowly and limited to those situations where what is at issue is "whether its statutory grant of power gives it the authority to decide a particular matter" (para. 59.)

49 Since *Dunsmuir*, the Supreme Court of Canada in *A.T.A. v. Alberta (Information & Privacy Commissioner)*, [2011] 3 S.C.R. 654 (S.C.C.) has once again clarified that:

> True questions of jurisdiction are narrow and will be exceptional. When onsidering a decision of an administrative tribunal interpreting or applying its home statute, it should be presumed that the appropriate standard of review is reasonableness.

50 In this case, as noted in *Montague*, there is no privative clause. With respect to the Tribunal's expertise, the Supreme Court of Canada had this to say in *Maybrun*, *supra* at paragraph 57 (regarding the Tribunal's predecessor, the Environmental Appeal Board):

> In establishing this process, the legislature clearly intended to set up a complete procedure, independent of any right to apply to a superior court for review, in order to ensure that there would be a rapid and effective means to resolve any disputes that might arise between the Director and the persons to whom an order is directed. The decision to establish a specialized tribunal reflects the complex and technical nature of questions that might be raised regarding the nature and extent of contamination, and the appropriate action to take. In this respect, the Board plays a role that is essential if the system is to be effective, while at the same time ensuring a balance between the conflicting interests involved in environmental protection.
>
> [Emphasis added.]

51 We accept that the Tribunal has specialized expertise in matters relating to the exercise of a discretionary power under s. 157.1 of the Act, its "home" statute.

52 For these reasons we find that the appropriate standard of review to apply to the Tribunal's decision is reasonableness.

53 The Appellant is also alleging that the Tribunal denied it natural justice when it refused to allow the City to put forward the evidence it wished to call and then found that the City had not put forward an environmentally-responsible solution. Any breach of the rules of natural justice must be reviewed on a standard of correctness.

54 The Respondents concede that if a tribunal has committed a breach of the rules of natural justice, then no standard of review analysis is required. A procedurally unfair decision cannot stand.

55 We agree that questions involving an alleged breach of the rules of natural justice do not require a standard of review analysis. A tribunal is required to act fairly, although what constitutes a fair procedure will vary depending on the nature of the circumstances surrounding the decision the tribunal is required to make: (*London (City) v. Ayerswood Development Corp.*, [2002] O.J. No. 4859, 167 O.A.C. 120 (Ont. C.A.); *Baker v. Canada (Minister of Citizenship & Immigration)*, [1999] 2 S.C.R. 817, 174 D.L.R. (4th) 193 (S.C.C.)).

The Evidentiary Ruling

56 Under the provisions of sections 15(1), 25.01 and 25 of the *Statutory Powers Procedure Act*, R.S.O. 1990, c. S.22, the Tribunal is given the authority to control its own process and may admit evidence that is "relevant" to the subject-matter of the proceeding. Thus, by implication, it is entitled to make rulings that certain evidence is irrelevant.

57 The Appellant argues that the Tribunal's evidentiary ruling prohibited it from calling the evidence it wished to call with respect to the "fairness" factors discussed in *Appletex* By finding this evidence irrelevant, the Tribunal effectively ignored two Divisional Court decisions, *Appletex* and *Montague*, decisions by which it was bound.

58 However, *Appletex* and *Montague* stand for the principle that the Director may take into account any one or more of the "fairness" factors in deciding whether to make an order under s. 157.1 of the Act against "a person who owns or has management or control of an undertaking or property." Neither case holds that the Director *must* take any one or more of these factors into account.

59 In *Appletex* the issue was whether the Tribunal had exceeded its jurisdiction by applying considerations of fairness. The Divisional Court found that it was "unable to agree with that submission" because under the Act the Director has a discretion as to whether or not to make a remediation order.

60 In *Montague*, the current owner had purchased property after a previous owner had contaminated it. The current owner had no knowledge of the contamination and had exercised due diligence when she purchased the property. The Director found that the current owner "must" be subject to a remediation order "by virtue of her status as an owner." The Tribunal overturned the Director and, after considering the "fairness" factors, declined to make any order "that would burden her with the financial responsibility for the cleanup" (para. 53.) The Divisional Court agreed with the Tribunal that the Director was not required to make an order against the current owner and declined to interfere with the Tribunal's decision to exercise its discretion to consider and apply the "fairness" factors.

61 In this case, the Tribunal did not refuse to hear any evidence regarding the "fairness" factors. For example, one of the "fairness" arguments that the City made at the hearing was that the original order against it was made in contravention of an agreement between it and the MOE. At the hearing, both the City and the MOE called evidence on this issue.

62 Rather, the Tribunal found that if the evidence spoke to issues of fault, that evidence was not relevant to the ultimate decision it had to make — namely, whether the Director's Order should be confirmed.

63 As already summarized, the City's proposed evidence spoke to the fact that it was an innocent owner, which was acknowledged by all parties. The City also sought to introduce evidence that one or more other parties were responsible for the contamination. The Tribunal was of the view that, in seeking to introduce this aspect of its evidence, the City was seeking to turn the appeal before the Tribunal into a hearing wherein the Tribunal would determine who was actually at fault for the contamination.

64 The Tribunal found that it was not the appropriate forum for this determination. Its mandate was to protect the environment, both through remediating existing damage and preventing further damage. As acknowledged by the Supreme Court of Canada in *Maybrun* at paragraph 59:

> Such a purpose requires rapid and effective means in order to ensure that any necessary action is taken promptly. This purpose is reflected both in the scope of the powers conferred on the Director and in the establishment of an appeal procedure designed to counterbalance the broad powers conferred on the Director by affording affected individuals an opportunity to present their points of view and assert their rights as quickly as possible.

65 The Tribunal found that there were other, more appropriate forums for determining liability. In this case, protecting the environment was a time sensitive matter. Determining fault was likely to be very time consuming.

66 The Tribunal was clear in its evidentiary ruling that it was in no way limiting the City's ability to make any arguments it wished about the fact that it would be "unfair" to make it pay for the remediation when it had done nothing to cause the contamination. All the Tribunal was saying was that there was no need for the City to call any evidence directed at establishing how innocent it was since everyone accepted that it was entirely so.

67 In regards to *Appletex*, the Tribunal pointed to changes that had occurred in the legal landscape since that case was decided in 1995. In *Appletex*, the Board was dealing with a situation where:

> Two businessmen invest their money in a bankrupt company which appears to have an experienced management team. When profits fail to materialize despite dramatic increases in production and sales, they find themselves increasingly involved in making management decisions in an attempt to safeguard their investment. Despite their efforts, the business fails and they lose their entire investment. The Ministry of Environment and Energy then orders them personally to pay for an extensive environmental clean-up of the abandoned site of the business. As none of the other persons subject to this order has any financial capacity to comply, this means that the entire clean-up costs falls on their shoulders. (*Appletex*, Reasons of the Tribunal, para. 2.)

68 In *Appletex*, the Tribunal decided that the MOE orders were unfair and relieved the two businessmen from much of their liability. In coming to the conclusion it did, the *Appletex* Tribunal commented upon the broad discretion afforded to the MOE to issue orders under the Act and upon the tension that exists between protecting the environment by expanding the pool of private parties who are available to pay for the costs of cleaning up the environment to parties such as officers, directors, lenders and receivers, and the need to avoid being unfair by simply attaching liability to "deep pockets." The *Appletex* Tribunal commented on the lack of policy guidance on resolving this tension. The Tribunal did find some guidance in the principles that were adopted by Core Group on Contaminated Site Liability in March of 1993 (a group composed of Ministers of the Environment from across the country and representatives from other environmental stakeholders.) According to the *Appletex* Tribunal, "the Core Group rejected a simplistic 'deep pockets' approach in favour of an approach that takes into account the circumstances of each case and looks at a variety of factors that come into play in deciding whether it is fair in the circumstances to impose liability" (*Appletex*, Reasons of the Tribunal, paragraph 115.)

69 In the case before us, the Tribunal correctly noted that the policy vacuum commented upon in *Appletex* had been filled by the Compliance Policy, a policy document that is specifically designed to provide guidance on how MOE officials are to exercise their discretion under the Act. Some aspects of the Compliance Policy explicitly disagree with the principles adopted by the Core Group in 1993. For example, the Core Group suggested that before imposing liability for clean-up on an owner who purchases a property that is already contaminated, it was relevant to consider whether that owner ought reasonably to have known of the contamination. The 2007 version of the Compliance Policy, on the other hand, specifically states that the "fact that an owner of a contaminated site may have purchased it without notice of the presence of contamination is irrelevant to the purpose of the Ministry legislation and generally will not be considered by the statutory decision-maker to be grounds for relieving that owner from liability under a control document" (Compliance Policy, section 3.)

70 In *Montague*, as noted above, the owner had purchased a property that was already contaminated and had exercised reasonable diligence before purchasing the property. The Tribunal relieved the owner from liability in spite of the "Buyer Beware" provisions of the Compliance Policy. This formed one of the bases for the Director's appeal of the Tribunal's order. The Divisional Court, at paragraph 59, had this to say about the Tribunal's failure to consider and/or apply the policy (note that one of the issues raised before the Divisional Court in *Montague* was whether the Tribunal appreciated that the compliance guideline was an official policy document as opposed to a proposed policy document):

> Counsel for the appellant concedes that such guidelines "need not be followed by a Director". Thus, there is no error of law in the Tribunal's statement to that effect. *Appletex* and other cases make it clear that the Tribunal must consider Ministry guidelines, and it is clear that the Tribunal did turn its mind to the guideline in question. It is equally clear that the Tribunal made a conscious decision not to follow the guideline and it is a fair inference that it would have done so irrespective of

whether the guideline was official or merely proposed. In the exercise of its discretion, the Tribunal was quite entitled to choose not to follow this guideline. While documents of this nature may guide its discretion, they cannot fetter it.

[Emphasis added.]

71 In the case at bar, the Tribunal made the choice to have its discretion guided by the Compliance Policy, a choice that the Divisional Court in *Montague* implicitly agreed it was entitled to make.

72 As noted by the Tribunal, the Compliance Policy makes reference to the role of a statutory decision-maker when a clean-up order might be issued to more than one person. It is not the role of the decision-maker to allocate liability or make findings of fault or degrees of fault. People who are named in an order are held to be jointly and severally liable for the clean-up. If determining fault or degrees of fault as between one or more potential orderees is irrelevant to the exercise of a statutory decision-maker under s. 157.1, such a determination of fault becomes much more irrelevant when the parties against whom the findings of fault are sought are not even potential orderees under s. 157.1. In this case the City was seeking to have the Tribunal consider evidence about the fault of the fuel provider, fuel tank manufacturer, insurance company, insurance adjuster, and the MOE itself, none of which were potential orderees under s. 157.1 of the Act. A provincial officer can only make s. 157.1 orders against a "person who owns or who has management or control of an undertaking or property."

73 The Tribunal also considered the fact that the Compliance Policy does provide specific guidance where the statutory decision-maker is considering making an order against an innocent or "victimized" owner like the City. According to section 2 of the Compliance Policy, such an owner will not be relieved of liability. If an exceptional or unusual circumstance existed, the timing and content of such an order could vary (but not whether it should be made in the first place). The Compliance Policy does acknowledge that there may be a "rare" circumstance when an innocent owner should not be named in an order, that is, where no environmental purpose would be served (for example, "where an owner's property has been contaminated by a groundwater plume originating from a source of contamination on an adjacent property and the required cleanup must, in order to be effective, focus upon the adjacent property rather than the owner's.") The case at bar does not involve such a rare circumstance.

74 Given the policy evolution since *Appletex* and the fact that *Appletex* and *Montague* do not stand for the proposition that a Tribunal is required to consider evidence of fault, we do not accept that the Tribunal committed an error in law when it found that evidence directed at fault was irrelevant, as it would not assist them in the decision that it ultimately had to make. In our view, the Tribunal's treatment of the law was reasonable.

The Tribunal's Decision on the Merits

75 The Appellant argues that the Tribunal's decision on the merits was unreasonable in that it violated a fundamental principle that is to guide the exercise of its discretion under the EPA: the "polluter pays" principle. Doing so was unfair and unreasonable, especially given the uncertainty surrounding whether the City would ever be reimbursed in another forum for the costs incurred from the real people at fault. According to the Appellant, since the Tribunal's decision on the merits, the City's ability to collect in another forum had been undermined by the Tribunal's own actions in adjourning the appeal relating to the City's issuance of an order under s. 100.1 of the Act.

76 In *Montague*, the Divisional Court does make reference to the "polluter pays" principle and notes at paragraph 1 that the Act "includes both a 'polluter pays' and an 'owner pays' enforcement mechanism."

77 Section 157.1 of the Act can be accurately described as an "owner pays" mechanism. It makes no reference to fault. It gives the provincial officer the discretion to make an order against an owner if the officer reasonably believes that such an order is necessary or advisable to protect the environment, which is the sole purpose of the Act.

78 Thus, to the extent that the Appellant is suggesting that an order against an owner must be unreasonable because it violates the "polluter pays" principle, the Tribunal was right — the Appellant's complaint is with the legislators who drafted the legislation, not with the statutory decision-makers whose mandate it is to act in accordance with the legislation as drafted.

79 In this case the provincial officer was faced with a situation where the contaminant on the owner's property was starting to cause damage to other parts of the environment. Left uncontrolled, that damage would only get worse. As noted by the Tribunal, this was a "recent spill" event, unlike the long-term contamination scenario that was the subject of *Appletex*. The owner of the adjoining property, where the contaminant had come from, was financially unable to remediate the damage. The provincial officer exercised her discretion and ordered the innocent owner to do the clean-up.

80 The Tribunal, in refusing to revoke the clean-up order, found that the MOE had exercised its discretion in a purposive manner consistent with the purpose of the Act. The exercise of discretion was also consistent with the Compliance Policy that was designed to assist officers in exercising their discretion under the Act. These findings were clearly reasonable.

81 With respect to the City's submissions about the Tribunal's reliance on s. 100.1 and its subsequent adjournment decision on this point, it is important to note that the Tribunal has not precluded the City from pursuing its s. 100.1 remedy. All it has said is that in view of the fact that the City's civil action in relation to the spill has been consolidated with another civil action in relation to the same spill, the appeal of the City's s. 100.1 order should be adjourned to see if liability could be worked out in the civil context. In coming to this decision, the Tribunal decided to monitor the civil action and specifically stated that if something changed that required the appeal to proceed sooner, it would reconsider its decision. At the time that the Tribunal adjourned the s. 100.1 appeal, the City had advised the Tribunal that there was no concern that the parties were going to dissipate assets.

The Rules of Natural Justice

82 The City also submits that when the Tribunal found that it had "not put forward relevant evidence of an environmentally responsible solution in support of a revocation of the Director's Order", the Tribunal committed a breach of the rules of natural justice. According to the Appellant, the evidence that the Tribunal refused to hear was the evidence that it was going to call on this issue. Clearly, according to the Appellant, the Tribunal breached the rules of natural justice when it refused to "hear and consider this admissible evidence before making a ruling with respect to the appropriateness of the order" (Appellant's Factum, para. 33.)

83 This submission — that the Tribunal breached the rules of natural justice when it refused to admit the evidence the City wished to call, and then found that the City had called no evidence about how the environment would be protected if the order against it were revoked — is problematic for several reasons. First, there is no evidence that the Tribunal ever precluded the City from calling evidence about how the environment would be protected if the order against it were revoked. Second, if evidence the City was precluded from calling were the evidence about how other parties were at fault, then this brings us back to the same argument that the City made when it sought to introduce the "fault" evidence in the first place. The Tribunal rejected the City's argument precisely because the City had not demonstrated how the proposed evidence was relevant to its overriding mandate of protecting the environment. In other words, the Tribunal did not accept that the City's proposed evidence about fault would assist it in coming up with an environmentally responsible solution if it revoked the Director's Confirming Order. I have already found that the Tribunal made no error in law in making this ruling. A lawful ruling on relevance of proposed evidence cannot constitute a violation of the rules of natural justice.

Conclusion

84 For these reasons the appeal is dismissed. The parties may make written submissions to us on the question of costs. These submissions shall be made within 14 days of the release of these reasons.

Appeal dismissed.

COURT FILE NO. 548/06
DATE: 20070718

SUPERIOR COURT OF JUSTICE – ONTARIO
DIVISIONAL COURT

BETWEEN:

KRAFT CANADA INC.

Moving Party

- and -

MENKES LAKESHORE LTD., AMEXON HOLDINGS INC., PETRO J. DEVELOPMENTS LIMITED, 36 PARK LAWN ROAD INC., CITY OF TORONTO, PROUDFOOT MOTELS LTD. and SOUTH ETOBICOKE INDUSTRIAL EMPLOYERS ASSOCIATION

Responding Parties

BEFORE: HIMEL J.

COUNSEL: *Timothy M. Lowman* for Kraft Canada
Mary Flynn-Guglietti and *Gina Rogakos* for Amexon Holdings
Alan B. Dryer and *Adam Brown* for Menkes Lakeshore Ltd.
Eileen P. Costello for Petro J. Developments Limited
Mark R. Flowers for 36 Park Lawn Road Inc.

HEARD: June 27 and 28, 2007

REASONS ON MOTION FOR LEAVE TO APPEAL

[1] Kraft Canada Inc. ("Kraft") seeks leave to appeal a decision of the Ontario Municipal Board issued on October 18, 2006. That decision approved applications by Menkes Lakeshore Ltd. and Amexon Holdings Inc. to amend the Official Plans and zoning by-laws to permit a mixed residential and commercial use designation of lands owned by each of the companies on Park Lawn Road in Toronto. The project consists of a ten storey office building, three residential towers with 1,200 units and a commercial podium on the Menkes lands and two residential towers with 588 units and a commercial podium on the Amexon lands. Kraft takes the position that the decision of the OMB is incorrect in law, that the Board breached principles of natural justice and that Kraft was denied a fair hearing.

FACTUAL BACKGROUND:

[2] Kraft has operated a large bakery adjacent to the Park Lawn Block in Toronto since 1948. The entire block comprises the land on the west side of Park Lawn Road

between Lakeshore Boulevard West and the CN Railway lines. The Park Lawn Block lies within the South Etobicoke area, which is characterized by a mix of industrial and residential uses.

[3] Menkes Lakeshore Ltd. ("Menkes") applied to the City of Toronto on May 2, 2002 and Amexon Holdings Inc. ("Amexon") applied to the City on October 28, 2002 proposing amendments to the Official Plans and zoning by-laws to permit the development of a number of residential buildings in a mixed use concept. The City deferred consideration of the amendments being sought on the basis that a comprehensive assessment of the area should be done.

[4] The parties appealed to the OMB. During that proceeding, two parties were added: Petro J. Developments, which owns 42 Park Lawn Road, and 36 Park Lawn Road Inc., which owns 36 Park Lawn Road. Petro J. and 36 Park Lawn did not file applications with the City and had not appealed the City's designation. However, on October 20, 2005, the OMB agreed to consider extending the same Official Plan treatment sought by Menkes and Amexon to the two "Intervening Properties". The Board accepted the opinions of the market and planning experts who testified that it would be most appropriate for all properties on the Park Lawn Block to have the same designation. Petro J. and 36 Park Lawn each support the changes sought by Menkes and Amexon and ask that the decision of the OMB stand, extending those changes to their properties as well.

[5] Kraft, which owns a neighbouring property located on the east side of Park Lawn Road, used primarily for the bakery operation, received party status for the hearing before the OMB. Kraft opposed the development claiming that residential use was not compatible with its bakery operation.

[6] The hearing before the Board took place over fifty days. The evidence called addressed matters concerning land use planning including potential fiscal, traffic, noise and odour impacts. On April 28, 2005, the Board heard submissions from the parties and issued a procedural order requiring that experts have the opportunity to review each other's reports by delivering them prior to May 31, 2005, and reply and meet prior to the hearing so that the parties would know the case they had to meet. Kraft attempted to introduce evidence concerning the noise issue after the experts of Menkes and Amexon produced their reports and without following that procedure. The Board did not allow Kraft to proceed in this fashion. Kraft did not seek to appeal or have that order reviewed at that time.

[7] The Board did not sit during the period November 2005 to April 2006. It issued a procedural order that new evidence or new studies would not be admissible when the hearing resumed. Following the hiatus, the Board refused to admit new reports adduced and refused to allow Kraft to cross-examine using new measurements from the expert. No challenge was taken at the time. No evidence was led regarding any study supporting City Council's decision to identify the area as an "employment district".

[8] The OMB issued a decision allowing the appeals in part and permitting the redevelopment with a mixed use concept consisting of residential and commercial uses over the entire Park Lawn Block including the Intervening Properties.

POSITIONS OF THE PARTIES:

[9] Kraft takes the position that the proposed redevelopment threatens the viability of the bakery operation. Kraft submits that the OMB erred in law in interpreting, and failing to apply the relevant legislation, regulations, policies, guidelines, and by-laws concerning mixed use designation. Between the time of the original applications and the hearing, the 2005 Provincial Policy Statement had come into force and the City of Toronto adopted the proposed new Official Plan. Kraft says the Board failed to consider and apply these documents. Furthermore, the Board violated principles of natural justice and denied Kraft a fair hearing. Kraft says the result is that it will face operating the Christie Bakery directly across the street from a large number of new residential units. Kraft filed a notice of appeal but then failed to perfect it in time. The parties moved to dismiss for delay but Ferrier J. granted an extension and set a timetable.

[10] Menkes and Amexon take a joint position that there is no reason to doubt the correctness of the decision of the OMB and that this matter is simply a dispute between neighbouring landowners as to the appropriateness of certain land uses to be permitted on private properties. The matter is not one of sufficient importance to merit the attention of the Divisional Court. They say that Kraft has not met the test for leave and the motion for leave to appeal should be dismissed. The two Intervening Properties support the decision of the OMB to amend the Official Plan and zoning by-laws to permit mixed commercial and residential uses. They ask that the approved changes apply to them as well. The remaining parties to the OMB hearing did not call a case or participate in the hearing and did not participate in the motion for leave to appeal to the Divisional Court.

ANALYSIS AND THE LAW:

Applicable General Principles:

[11] The standard to be applied on a motion for leave to appeal a decision of the OMB to the Divisional Court is that leave should only be granted where: (1) there is some reason to doubt the correctness of the Board's decision on a point of law and (2) the point of law is of sufficient importance to merit the attention of the Divisional Court: see *Toronto (City) v. Avro Quay Ltd*., [2002] O.J. No. 1470 (Div.Ct.) at para. 22; *Concerned Citizens of King Township Inc. v. King (Township*), [2000] O.J. No. 3517 (Div.Ct.) at para. 10; *Zellers Inc.* v. *Royal Cobourg Centres Ltd.,* [2001] O.J. No. 3792 (Div.Ct) at para. 9.

[12] On a leave application, the onus is on the party seeking leave: see *Neebing (Municipality) v. Dale,* [2003] O.J. 3793 (Sup. Ct.) at para. 12, 43 M.P.L.R. (3d) 263 (Sup.Ct.) at 6. Appeals are on questions of law alone and the court must give deference

to the Board's decision in keeping with the degree of independence and expertise of the Board and its members.

[13] Good reason to doubt the correctness of the decision does not mean that the decision is wrong or probably wrong. It is sufficient to show that the correctness of the order is open to very serious debate: see *Ash v. Corp. of Lloyd's* (1992), 8 O.R. (3d) 282 (Ont. Div. Ct.); *Sunnybrae Farms Ltd. v. Ontario Egg Producers' Marketing Board* (1977), 3 C.P.C. 348 (Ont. H.C.) at 350. Furthermore, good reason to doubt the correctness of a decision means there is good reason to doubt the correctness of the *entire* order.

[14] In addressing the issue of sufficient importance, the court must be mindful that matters of importance must be general and relate to matters of public rather than private importance or matters must be relevant to the development of the law and administration of justice: see *Rankin v. McLeod, Young, Weir Ltd.* (1986), 57 O.R. (2d) 569 (H.C.) at 575. For example, disputes about the use of specific properties may not be of sufficient importance to merit the attention of the court: see *Central Park Lodges Ltd. v. Caregard Group* (2000) 13 M.P.L.R. (3d) 204 (Div. Ct.) at para. 18.

Did the Board fail to apply the 2005 Provincial Policy Statement or the new Official Plan in reaching its decision and, thereby, commit an error of law?

[15] Kraft argues that the OMB erred in law by failing to apply to these applications the 2005 Provincial Policy Statement (PPS) which came into effect between the time of the original applications and the first hearing before the Board. The Policy Statement had been issued under section 3 of the *Planning Act*, R.S.O. 1990, c. P. 13, and, according to the moving party, the statement and amendments introduced fundamental changes. In particular, the 2005 PPS provided that the OMB must promote economic development and competitiveness by "…planning for, protecting and preserving employment areas for current and future use." The Board determined that the 2005 PPS did not apply to the proceeding because the applications were brought before it came into force. Instead, it applied the 1996-7 PPS.

[16] Kraft argued that, by considering the related applications of the Intervening Properties and consolidating their requests with the earlier applications in order to treat the Park Lawn Block as a whole, the Board was required to apply the new Policy Statement. Policy 4.1 of the 2005 PPS stated that it applies to "all applications, matters or proceedings commenced on or after March 1, 2005."

[17] In my view, the Board was correct in its interpretation that the applications before the Board were those submitted by Amexon and Menkes in 2002. The Board based its decision upon the principle outlined in the case of *Clergy Properties Ltd. v. City of Mississauga,* [1996] O.M.B.D. No. 1840, which held that the decision should be based upon relevant policies and legislation in place at the time of the application. The Board also based its decision on the clear language of the 2005 PPS.

[18] In counsel's argument on this motion for leave, counsel relied upon Section 3(5) of the *Planning Act*, which states as follows:

> A decision of the council of a municipality, a local board, a planning board, a minister of the Crown and a ministry, board, commission or agency of the government, including the Municipal Board, in respect of the exercise of any authority that affects a planning matter,
> (a) shall be consistent with the policy statements issued under subsection (1) that are in effect on the date of the decision; and
> (b) shall conform with the provincial plans that are in effect on that date, or shall not conflict with them, as the case may be.

[19] This provision, however, came into effect on January 1, 2007. I note the earlier provision used the words "having regard to". In any event, a proper interpretation of the use of a Policy Statement is that the OMB is required to consider and take into account a policy statement but is not required to adopt it. The Board is also entitled to deference on planning matters.

[20] I do not see any basis to find that the Board erred in its consideration of the 1996-7 PPS and not the 2005 document. It did not err in finding that the 2005 PPS did not apply and that the Board's jurisdiction was triggered by the appeals filed by Menkes and Amexon, which pre-dated the 2005 document. Adding the two Intervening Properties and modifying the Plan did not trigger the application of the 2005 PPS.

[21] Kraft takes the position that the Board erred in not considering the new proposed City of Toronto Official Plan. The Board, in its decision, considered the application of the MetroPlan, the City of Etobicoke Official Plan and the Park Lawn Road/Lakeshore Boulevard Secondary Plan and found that there was appropriate compliance with these documents. It stated that it was also considering the new Official Plan because the City was in the process of developing it at the time. It applied the principle enunciated in *Boothman v. Newcastle (Town)*, [1993] O.M.B.D. No. 442, that the new Plan is "admissible, relevant but not determinative." It considered the new Plan concerning the Park Lawn Block "as part of the Board's practice to have regard to the decisions of Council."

[22] Kraft also argues that the OMB erred by not giving weight to the City's decision to identify the Park Lawn Block as an "Employment District" and designate it as an "Employment area". Kraft says that that designation is strong evidence of its decision to protect the long-term future of the Park Lawn Block for employment purposes. The Board held that the fact that City Council designated the Park Lawn Block as an Employment Area in the new City of Toronto Official Plan was not a relevant consideration in that there was no evidence led supporting that designation nor any comprehensive review or analysis that set out the planning merits of that designation. Rather, it was Kraft that had sought the designation of the Park Lawn Block as an employments area and a decision was made without supporting planning analysis.

[23] In my view, there is no good reason to doubt that the Board's application of relevant policy statements, legislation, and the various Official Plans was correct. The Board was satisfied that the proposed amendments conformed to the governing documents, from the perspective of impact upon employment, transit, traffic, density, compatibility with existing industry, noise, air quality, and odour. The Board held that a mixed use designation is an employment generating designation and supports economic development, all of which is consistent with the Provincial Policy Statement. Although the new City of Toronto Official Plan is not determinative in this case, the Board considered elements of the Plan that addressed the Park Lawn Block. The Board considered the issue of land use for employment purposes when considering the proposed amendments, accepted the market evidence and the expert opinion and held that "the proposals to redesignate to, and redevelop as, mixed -use are consistent with the Provincial Policy Statement."

[24] In summary, the Board considered the applicable documents and attached weight to those which it deemed relevant to the case before it and there is no good reason to doubt the correctness of the Board's decision in this regard.

Did the Board err in extending the re-designation applications to the two Intervening Properties?

[25] Kraft argues that the OMB erred in law and exceeded its jurisdiction by applying a mixed use (residential and commercial) designation to the Intervening Properties and amending the Official Plan relating to those properties, although Petro and 36 Park Lawn did not file a proposal for future use with the City nor did they make an application to the OMB to redesignate the properties as mixed use, or appeal the designation in the Official Plan. Kraft says that the Board erred in law by making a decision without having a comprehensive planning study available and by expanding Official Plan amendments to the Intervening Properties.

[26] In its decision, the Board noted that all of the expert planning witnesses who appeared before it agreed that the Park Lawn Block should "be considered as a whole" and agreed that the properties had similar characteristics. Kraft opposed the re-designation of the two Intervening Properties for the same reasons that it opposed the re-designation of the Menkes and Amexon properties.

[27] The Board's decision to modify and approve the proposed Official Plan amendments is permitted under section 17(50) of the *Planning Act*. The Board had the jurisdiction to modify and approve all or part of the proposed Official Plan amendments before it: see section 22(11). The term "modify" has a broad definition providing a power to vary or amend: see *Cloverdale Shopping Centre Limited v. Etobicoke (Township),* [1966] 2 O.R. 439 (C.A.) at 454. In that case, the court held that modify included the concept of "extend or enlarge". Restricting the Board's power to modify is not limited to the boundaries of the land being considered: see *Lawson Estates Ratepayers Assn. (Trustees of) v. Grace Communities Corp.*, [1993] O.J. No. 1808 (Div. Ct.) at 4. The Board has general jurisdiction to modify Official Plan amendments, which

includes expanding boundaries of an Official Plan amendment and a change of use: see *Maplehurst Bakeries Inc. v. Brampton (City),* [1998] O.J. No. 6092 (Div.Ct.). The Board is not required to undertake a planning study before modifying an Official Plan amendment.

[28] In my view, the Board acted properly on the evidence before it concerning land use planning and accepted that the Park Lawn Block should be considered as a whole. It was sensible and practical to consider the use of the Intervening Properties at the same time as the Amexon and Menkes proposals and to address the question of Official Plan amendments in a comprehensive manner. What the Board did is precisely what is contemplated in the powers provided in the legislation.

Did the Board breach the rules of natural justice?

[29] Kraft says that the OMB violated the rules of natural justice by refusing to allow it to lead evidence showing that its operation would be adversely affected by the residential uses proposed by Menkes and Amexon. In particular, Kraft was not permitted to call further noise expert evidence addressing the sound impact of Kraft truck delivery activities and the question of truck banging.

[30] Under the *Statutory Powers Procedure Act*, R.S.O. 1990, c. S. 22 (*SPPA*), s. 25.0.1, the Board, as an administrative tribunal exercising a statutory power of authority, maintains absolute jurisdiction and control over its own procedure. It has the power to determine its own procedures and practices and to make procedural orders: see *Ontario Municipal Board Act*, R.S.O. 1990, c. O. 28, ss. 37(a) and 91; *Ontario Municipal Board Rules of Practice and Procedure.* Section 15 of the *SPPA* gives administrative tribunals the express statutory power to exclude evidence that is unduly repetitious.

[31] The authorities are clear that courts should give deference to procedural orders and rulings and should be reluctant to interfere with procedural orders within a tribunal's jurisdiction: see *Zellers Inc. v. Royal Cobourg Centres Ltd., supra; Lafarge Canada Inc. v. 1341665 Ontario Ltd.,* [2004] O.J. No. 1572 (Div. Ct.)*; Clark v. Essa* (2007), 156 A.C.W.S. (3d) 516. A party who is dissatisfied with an order of the Board should seek leave to appeal in a timely manner before the Board commences its hearing on the merits: see *South Etobicoke Residents Ratepayers Association. Inc. v. Toronto (City),* [2001] O.J. No. 3182 (Div. Ct.). Refusing to admit evidence is not an automatic breach of natural justice that justifies intervention of the court. Only where the refusal to admit evidence has a significant impact on the fairness of the proceeding amounting to a clear denial of natural justice should the court interfere: see *University du Quebec a Trois-Rivieres v. Larocque*, [1993] 1 S.C.R. 471 (S.C.C.).

[32] With reference to the procedural orders made by the Board in this case, I note that Kraft did not challenge the OMB rulings at the time they were made. Kraft was aware of the noise reports and witness statements from the noise experts and attended meetings in advance of the hearing as provided by the Procedural Order. Kraft could have attempted to bring a motion to seek to introduce additional evidence, a process which was provided

in the Procedural Order. Kraft chose not to do so. Similarly, Kraft attempted to introduce evidence gathered during the hiatus, thus contravening the Procedural Order made on November 9, 2005. The Board ruled that the two new reports that had not been previously disclosed would not be admitted.

[33] There is no reason to interfere with the Board's decision not to permit Kraft to introduce additional sound level histories and evidence relating to truck banging that it had before the hearing, but chose not to introduce. The Board excluded evidence about noise impact studies collected during the hiatus in the proceeding after other experts had been examined and cross-examined. Kraft chose not to comply with the Procedural Orders and sought to introduce evidence after a significant portion of the hearing had been completed. There was no breach of the rules of natural justice and there is no basis for the Divisional Court to interfere with the Board's orders concerning the admission of evidence.

DECISION:

[34] In my view, there is no good reason to doubt the correctness of the decision of the OMB. The hearing took place over fifty days and involved evidence from twenty-five experts. The judgment rendered provides a careful analysis with detailed reasons for the decision set out in forty pages. In summary, this is not a case where "the correctness of the decision is open to very serious debate." Moreover, it cannot be said that the proposed appeal is of sufficient importance to justify granting leave. There are no matters raised of broad significance which transcend the interests of the parties and warrant resolution by a higher level of judicial authority: see *Klein v. American Medical Systems Inc.*, 2006 CarswellOnt. 2306 (Ont. Div. Ct.).

RESULT:

[35] For the reasons outlined, the application for leave to appeal the decision of the Ontario Municipal Board is dismissed. Having heard submissions on costs, I exercise my discretion under section 131 of the *Courts of Justice Act* and consider the factors outlined in Rule 57.01(1) of the *Rules of Civil Procedure* and fix costs of this motion for leave to appeal. Kraft, the moving party, shall pay costs in the amount of $61,000 inclusive of disbursements (which I find to be reasonable and necessary) and applicable GST to the responding party Menkes Lakeshore Ltd., costs of $40,783.24 inclusive of disbursements and GST to Amexon, costs of $17,000 inclusive of disbursements and applicable GST to 36 Park Lawn Road Inc. and costs of $ 9,000 inclusive of disbursements and applicable GST to Petro J. All costs are fixed on the partial indemnity scale and are payable within thirty days.

Date: July 18, 2007

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HIMEL J.

2011 ONSC 4086
Ontario Superior Court of Justice (Divisional Court)

Sierra Club Canada v. Ontario (Ministry of Natural Resources)

2011 CarswellOnt 5889, 2011 ONSC 4086, [2011] O.J. No. 3071, 204 A.C.W.S. (3d) 222

Sierra Club Canada, Applicant and Her Majesty the Queen in Right of Ontario as Representative of the Ministry of Natural Resources and the Ministry of Transportation, Respondents

J. Wilson J., Jennings J., Lederer J.

Heard: May 18, 2011
Judgment: June 29, 2011
Docket: 412/10

Counsel: Paula Boutis, for Applicant
William J. Manuel, Lise Favreau, for Respondents

Decision of the Board:

Preliminary Motion to strike three affidavits

1 The applicant Sierra Club Canada is seeking judicial review of the decision of the Minister of Natural Resources dated February 9, 2010 granting a permit to the Ministry of Transportation pursuant to section 17(2)(d) of the *Endangered Species Act, 2007*, S.O. 2007, c. 6 (the ESA). The permit allows the development of the proposed Windsor Essex Parkway portion of the Detroit River International Crossing project (the Decision). It is the applicant's position that the project places in jeopardy the survival or recovery of two species of snake — the Butler*'s* Gar*t*ersnake and the Eastern Foxsnake (Carolinian population) — as well as the colicroot plant.

2 The Respondents brought a preliminary motion at the opening of this three-day hearing before the panel to strike two affidavits filed by the applicant in their entirety, and to strike aspects of a third affidavit.

3 The three affidavits that the respondents seek to strike include:

- the affidavit of Dr. Robert Murphy — a professor in the Department of Ecology and Evolutionary Biology at the University of Toronto,

- the affidavit of Ms. Diane Saxe — a lawyer with expertise in the environmental law field, and

- the affidavit of Dan McDermott — the Director of the Ontario Chapter of Sierra Club Canada.

4 Dr. Murphy was retained some six months after the Decision was rendered to conduct a peer review of one of the reports drafted by an expert retained by the Ministry with respect to the Eastern Foxsnake. Dr. Murphy's affidavit also presents evidence on scientific authorities that were available prior to the rendering of the Minister's Decision.

5 Ms. Saxe's affidavit outlines evidence about licencing procedures applicable in environmental assessments conducted under other statutory regimes, and she provides opinion evidence about how she believes the ESA should be interpreted.

6 Mr. McDermott provides a detailed affidavit of some 276 paragraphs attaching numerous exhibits, regarding historical matters at issue in this application.

7 We are of the view that this motion should have been brought prior to the hearing by the panel, in order to clarify the contents of the record prior to factums being filed. Proceeding in such a manner would have enabled the parties to define the issues for the hearing based upon properly admissible evidence. I note that this was the procedure followed in the decision of *Hanna v. Ontario (Attorney General)*, 2010 ONSC 4058 (Ont. Div. Ct.). If the motion judge is unsure about the relevance of certain material, those issues may be left to be determined by the panel hearing the judicial review.

8 To fail to define the appropriate record for the Court before the hearing encourages the proliferation of collateral issues, as occurred in this application. Filing material by one party inevitably precipitates a response from the opposite party. The consequence of failing to define the record is a proceeding before this court that becomes unnecessarily complicated, expensive and lengthy. For the parties and for the court, the ground is continually shifting, and the core issues may be eclipsed by the procedural issues.

9 Illustrative of why this motion should have been brought before the hearing is the chart prepared by the respondent that was provided to the Court the day before the hearing began. This chart spans some 75 pages to explain what paragraphs of the affidavit of Mr. McDermott should or should not be considered by the court based upon the parties' agreement, which was reached shortly before the hearing. There remained eight areas of dispute.

10 Although this narrowing of the issues was commendable, it should have taken place well before the hearing of this matter. The factums had already been prepared. This court should not be asked to edit the factums to extract references to inadmissible evidence.

The principles that apply to the filing of material with the Court in a judicial review application

11 The scope of appropriate materials to be filed in a judicial review application is limited. The principles bear repeating to avoid this sort of problem in the future.

12 Judicial review proceedings have a narrow focus. Brown and Evans, in *Judicial Review of Administrative Action in Canada* (Canvasback, looseleaf), have described the court's role on judicial review as follows (at para. 12:3100):

> On an application for judicial review, the courts play only a residual role in reviewing the findings of fact made by administrative adjudicators. Generally speaking, in the absence of a statutory right of appeal, the courts are confined to ensuring that the findings on which the decision is based are supported by some logically probative evidence on which the decision-maker may lawfully rely.

13 The general rule is that, on an application for judicial review, affidavits containing material that was not before the decision-maker at first instance will not be allowed. The record that goes before the reviewing court should essentially be the material that was before the decision-maker at the time the decision was being made. See e.g.: *Mianowski v. Ontario (Human Rights Commission)*, 2003 CarswellOnt 3671 (Ont. Div. Ct.); *Lincoln (County) Board of Education v. Ontario (Information & Privacy Commissioner)* (1994), 76 O.A.C. 235 (Ont. Div. Ct.) ; *Ontario Hydro v. Ontario (Assistant Information & Privacy Commissioner)* (1996), 97 O.A.C. 324 (Ont. Div. Ct.).

14 Affidavit evidence is permissible to supplement the record in exceptional circumstances to demonstrate an absence of evidence on an essential point in the decision (which is to say, to demonstrate a jurisdictional error) or to show a breach of natural justice that cannot be proved by mere reference to the record: *Keeprite Workers' Independent Union v. Keeprite Products Ltd.* (1980), 114 D.L.R. (3d) 162 (Ont. C.A.), at 170 .

15 We reiterate that affidavit evidence to supplement the record may be admissible in exceptional circumstances only.

Consideration of the affidavits filed

16 The applicant retained Dr. Murphy as an expert six months after the Decision was rendered in order to have Dr. Murphy conduct a peer review of the independent expert reports prepared by Rob Wilson of RiverShore Environmental Solutions Inc., James Kastra and Dr. Ronald Brooks with respect to each snake species.

17 The applicant had been provided with the reports prepared by the experts appointed by the Ministry before the Decision of the Minister was made, and the applicant took the opportunity to make submissions in writing at that time. The applicant did not provide the Minister with any alternative expert reports in support of its concerns at that time.

18 Clearly, it is not appropriate to allow the applicant's expert to conduct a peer review of expert reports relied upon by the Minister months after the Decision when the applicant had the opportunity to retain independent experts prior to the Decision being made. We conclude without hesitation that this affidavit material is not admissible. There are no exceptional circumstances justifying its admission. The affidavit of Dr. Murphy is therefore struck.

19 The affidavit of Ms. Saxe considers the interpretation of other legislation that is not applicable in this case. We are of the view that this information is irrelevant and hence inadmissible. The affidavit also contains opinion evidence about how the ESA should be interpreted. With respect, it is not appropriate for a lawyer to give an opinion about how new legislation is to be interpreted. This is the Court's function. The affidavit of Ms. Saxe is therefore struck as irrelevant and inadmissable.

20 The very lengthy affidavit of Mr. McDermott spans some 248 paragraphs. The affidavit contains extensive hearsay evidence, opinion evidence, and information based upon belief where the source of the information is not specified. The affidavit also contains numerous documents that were available only after the Decision was made, and other documents arising from a Federal Court challenge launched by the applicant.

21 With respect to the affidavit of Mr. McDermott, we conclude that the contested portions of the affidavit, with the exception of one e-mail chain, should be struck as irrelevant or not properly admissible. We conclude that the e-mail chain regarding whether or not the applicant's experts came to an agreement with the Ministry staff about appropriate mitigation methods is admissible, and may be considered by the Court.

22 It became clear as the matter was argued that the voluminous additional material was not relevant to the question of whether the Minister had considered the factors enunciated in section 17(2)(d) of the ESA and whether the Decision of the Minister was reasonable.

23 We repeat our concern that generally these procedural issues meant to properly define the record need to be determined before the date of the hearing, and indeed before the parties' facta are finalized. The costly last-minute filings that occurred in this case undermine the Court's ability to efficiently and fairly deal with the matters in issue and should be avoided.